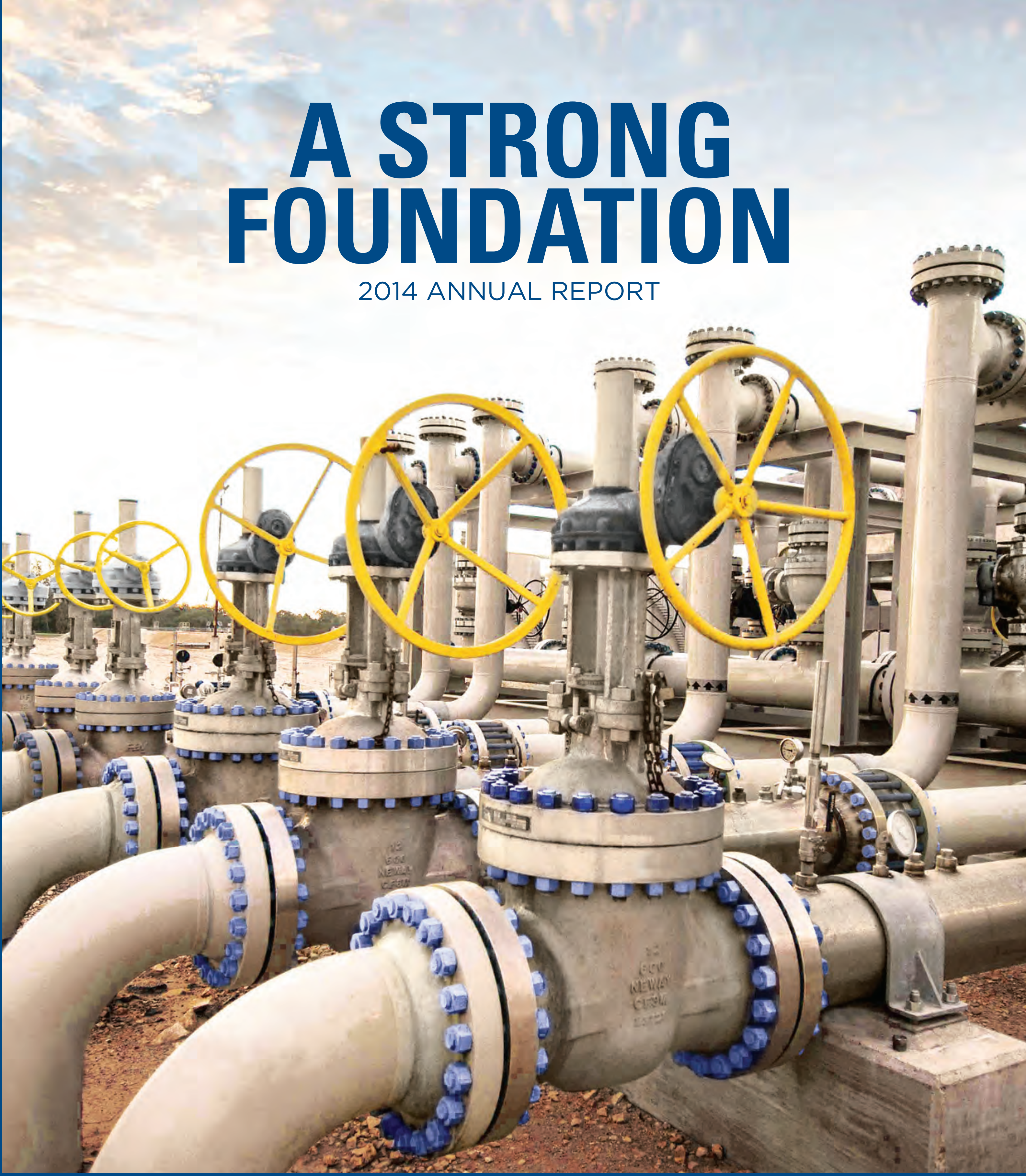
A STRONG FOUNDATION

2014 ANNUAL REPORT



Denbury

STRENGTH IN OUR OPERATIONS

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FORWARD-LOOKING STATEMENTS

The data contained in this annual report that are not historical facts are forward-looking statements that involve a number of risks and uncertainties. Such statements may relate to, among other things: long-term strategy; anticipated levels of future dividends and their rate of growth and sustainability; the length or severity of the oil price downturn in late 2014 and early 2015; forecasts of capital expenditures, drilling activity and development activities; timing of carbon dioxide (CO_2) injections and production response to such tertiary flooding projects; estimated timing of pipeline construction or completion or the cost thereof; anticipated dates of completion of industrial plants to be constructed or under construction and the initial date of capture and amount of anthropogenic CO_2; estimates of liquidity, costs, forecasted production rates or peak production rates and the growth thereof; estimates of hydrocarbon reserve quantities and values, including potential or recoverable reserves, CO_2 reserves, and helium reserves; projected future hydrocarbon prices or costs; estimated future cash flows, including from our hedging positions, or uses of cash; availability of capital or borrowing capacity; estimated rates of return and overall economics; and anticipated availability and cost of equipment and services. These forward-looking statements are generally accompanied by words such as "believe", "estimated", "preliminary", "projected", "potential", "anticipated", "forecasted", "expected", "assume" or other words that convey the uncertainty of future events or outcomes. These statements are based on management's current plans and assumptions and are subject to a number of risks and uncertainties as further outlined in our most recent Form 10-K filed with the SEC. Therefore, actual results may differ materially from the expectations, estimates, forecasts, projections, or assumptions expressed in or implied by any forward-looking statement herein made by or on behalf of the Company.

Cautionary Note to U.S. Investors — Current SEC rules regarding oil and gas reserve information allow oil and gas companies to disclose in filings with the SEC not only proved reserves, but also probable and possible reserves that meet the SEC's definitions of such terms. We disclose only proved reserves in our filings with the SEC. Denbury's proved reserves as of December 31, 2014 were estimated by DeGolyer & MacNaughton, an independent petroleum engineering firm. In this annual report, we make reference to probable and possible reserves, some of which have been estimated by our independent engineers and some of which have been estimated by Denbury's internal staff of engineers. In this annual report, we also refer to estimates of resource or reserves "potential", barrels recoverable, or other descriptions of volumes potentially recoverable, which in addition to reserves generally classifiable as probable and possible (2P and 3P reserves), include estimates of reserves that do not rise to the standards for possible reserves, and which SEC guidelines strictly prohibit us from including in filings with the SEC. These estimates, as well as the estimates of probable and possible reserves, are by their nature more speculative than estimates of proved reserves and are subject to greater uncertainties, and accordingly the likelihood of recovering those reserves is subject to substantially greater risk.

DENBURY'S CO_2 CYCLE

STEP 1

CO_2 SOURCES & CAPTURE

The first step in implementing a carbon dioxide enhanced oil recovery ("CO_2 EOR") project is to secure access to substantial volumes of CO_2. Denbury sources CO_2 both from naturally occurring underground reservoirs and from industrial sources, which capture, process and then compress the CO_2 for delivery into a pipeline network. The CO_2 captured from industrial sources (which is sometimes referred to as anthropogenic or man-made CO_2) could otherwise be released into the atmosphere. For our Gulf Coast assets, Denbury sources naturally occurring CO_2 from Jackson Dome in Mississippi, and industrial CO_2 from two facilities: one in Port Arthur, Texas and one in Geismar, Louisiana. For our Rocky Mountain region, Denbury sources CO_2 from the Lost Cabin Gas plant and the Shute Creek plant in Wyoming.

STEP 2

CO_2 TRANSPORTATION

The second step is transporting the CO_2 from the source to the oil field. We operate or control over 1,100 miles of CO_2 pipelines and are continually expanding this network to transport naturally occurring CO_2 and CO_2 from industrial sources to our tertiary fields. We currently utilize, on average, over 130 million cubic feet of CO_2 from industrial sources per day and anticipate additional CO_2 from industrial sources from currently planned or future construction of facilities in our Gulf Coast region.

STEP 3

CO_2 INJECTION

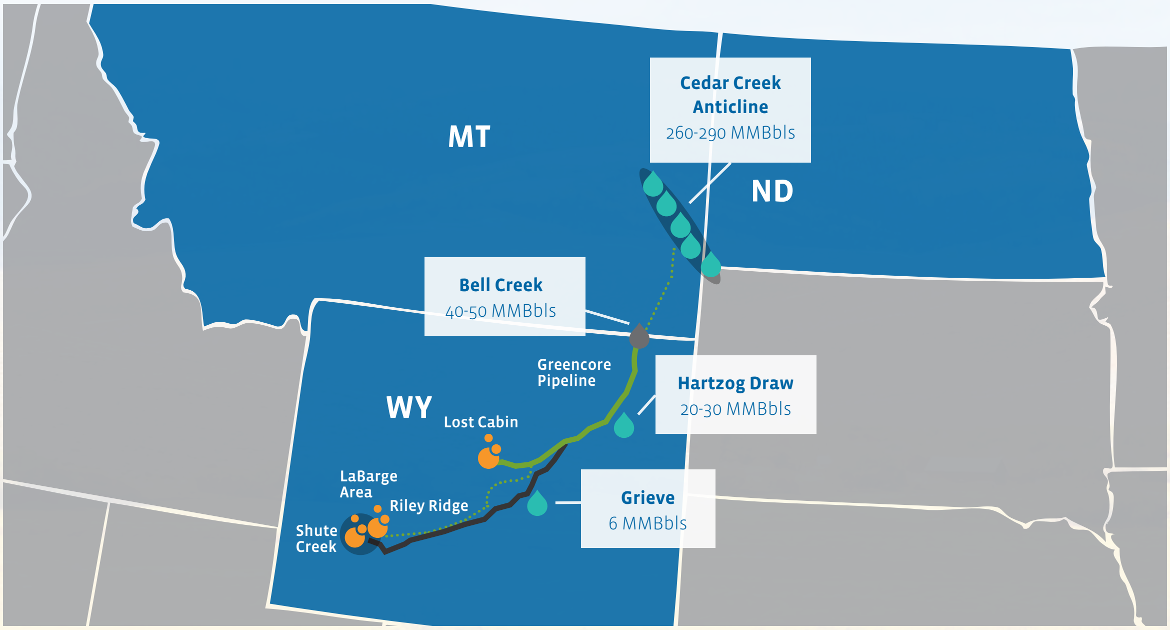
The third step is to inject the CO_2 into the oil-bearing reservoir through a wellbore. The injected CO_2 moves through the reservoir, mixing with the crude oil trapped there. The CO_2 acts to separate the oil from the reservoir rock and increase the oil's mobility within the reservoir. The mixture is driven through the formation into a producing wellbore, where it then comes to the surface, increasing the field's oil production. To date, our CO_2 EOR operations have resulted in the gross production of over 100 million barrels of oil that may not have otherwise been recovered.

STEP 4

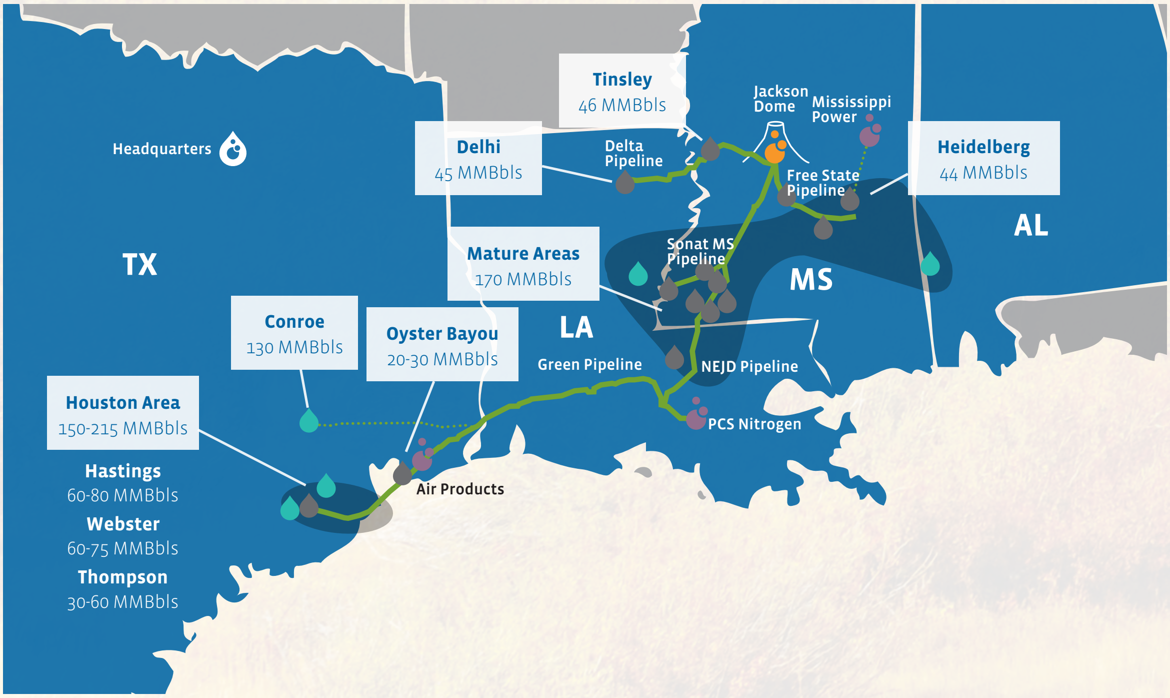
CO_2 EOR BENEFITS & STORAGE

CO_2 EOR operations provide considerable economic and environmental benefits. The economic benefits of CO_2 EOR include the creation of jobs due to large cash investments required to implement and operate a CO_2 EOR project along with tax payments to local governments. Our CO_2 EOR operations also provide an environmentally responsible method of utilizing and ultimately storing CO_2 in underground oil reservoirs while also making our nation more energy secure.

ROCKY MOUNTAIN REGION: POTENTIAL TERTIARY RESERVES[1]

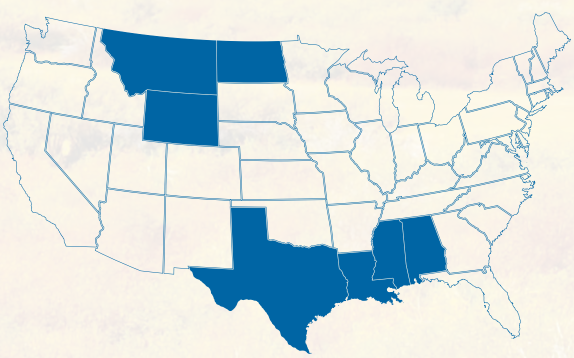


GULF COAST REGION: POTENTIAL TERTIARY RESERVES[1]



Our oil and natural gas properties are concentrated in the Gulf Coast and Rocky Mountain regions of the United States. Currently our properties with proved and producing reserves in the Gulf Coast region are situated in Mississippi, Texas, Louisiana and Alabama, and in the Rocky Mountain region are situated in Montana, North Dakota and Wyoming. Our primary focus is using CO_2 in EOR, and our current portfolio of CO_2 EOR projects provides us significant oil production and reserve growth potential in the future.

"WE BELIEVE OUR INVESTMENTS, OUR EXPERIENCE AND OUR ACQUIRED KNOWLEDGE GIVE US A STRATEGIC AND COMPETITIVE ADVANTAGE, AND WE LOOK FORWARD TO CONTINUED LEADERSHIP IN THIS ARENA FOR MANY YEARS."



Tertiary & Total Company Potential (MMBOEs)

Tertiary	
Proved(1)	215
Potential(2)	679
Produced-to-Date(3)	100
Total Tertiary(2)	**994**
Total Company Potential(4)	**1,200**

- Headquarters
- Existing CO_2 Pipelines Owned or Operated by Denbury
- Denbury Proposed CO_2 Pipelines
- CO_2 Pipelines Not Owned or Operated by Denbury
- Denbury CO_2 EOR Fields
- Denbury Future CO_2 EOR Fields
- CO_2 Resources Owned or Contracted
- Industrial CO_2 Sources: Producing or Pending Start Up

(1) Potential, proved and produced-to-date tertiary reserves estimated as of 12/31/14 based on a range of recovery factors. Proved reserves based on year-end 12/31/14 SEC prices.

(2) Using mid-points of ranges.

(3) Produced-to-date is cumulative tertiary production through 12/31/14.

(4) Proved and potential conventional and tertiary reserves estimated as of 12/31/14 based on a range of recovery factors. Excludes tertiary production to date.

DEAR FELLOW SHAREHOLDERS

Although oil prices declined precipitously in the fourth quarter of 2014 and the lower oil price environment has continued into 2015, we have unique flexibility in our business model to adjust our capital spending in times of uncertainty while maintaining our strong financial position. As a result, in November 2014, we took a decisive and proactive step by significantly reducing our projected 2015 capital spending to $550 million, or half of our combined 2014 capital spending of $1.1 billion.

We are able to do this because of the unique production and cash flow profile of our oil and natural gas assets, which are almost all either current or future carbon dioxide enhanced oil recovery ("CO_2 EOR") projects. As we demonstrated in 2014 by balancing our capital expenditures and dividends with our cash flow from operations, we are committed to strong financial discipline, and we believe that we can fund our 2015 capital program and dividends with projected cash flow from operations.

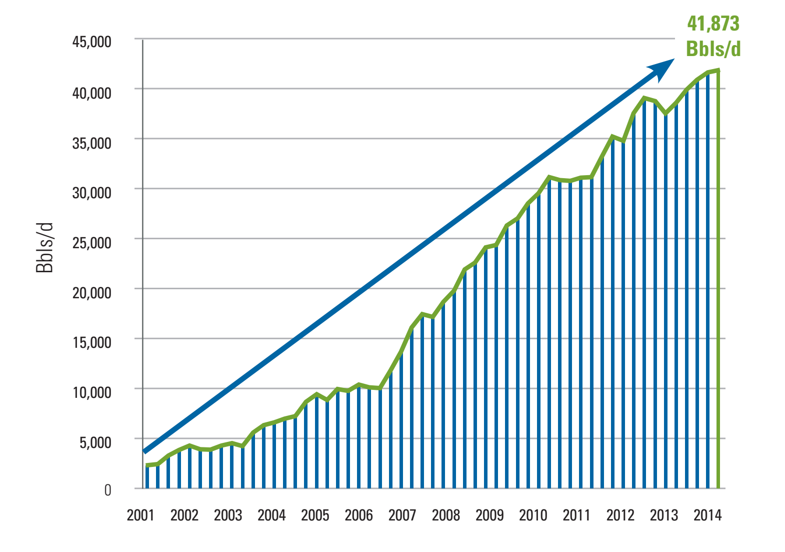
During this period of reduced capital spending, we are leveraging the talents of our dedicated workforce to enhance our current asset base. At the end of 2014, we assembled multi-disciplinary innovation and improvement teams among existing company personnel and commenced detailed evaluations of our fields and operational performance to identify and improve our operating efficiency and reduce costs. I am pleased to report that these evaluations are going well. The innovation and improvement teams have presented many potentially rewarding ideas, and we are starting to evaluate and prioritize these ideas to work toward implementation. In addition to our innovation and improvement teams, we continue to explore ways to reduce costs and increase efficiencies in everything we do, and I expect to see additional improvements in our cost control initiatives as we move forward.

On the operational front, we view 2014 as a year we can build upon. There were several bright spots for Denbury as we delivered average daily production of 74,432 barrels of oil equivalent ("BOE") per day in 2014. We increased our average tertiary oil production to a new record level of 41,079 barrels per day ("Bbls/d") in 2014, a 7% increase from average tertiary oil production in 2013, primarily due to continued field development and expansion of facilities in our existing CO_2 floods at Hastings, Heidelberg, Oyster Bayou, Tinsley, and Bell Creek fields. Considering our reduced capital spending plan for 2015, we expect to maintain production relatively flat with 2014 levels.

Denbury's total estimated proved oil and natural gas reserves at December 31, 2014, were 438 million BOE ("MMBOE"), of which 83% was crude oil, condensate, and natural gas liquids, 77% was proved developed, and 49% was attributable to Denbury's CO_2 EOR operations. The net reduction of total proved reserves of 30 MMBOE during 2014 was primarily the result of 2014 production. In 2014, we did not commence any new floods, although additional phases of existing CO_2 floods were implemented, moving proved undeveloped ("PUD") reserves into proved developed reserves, lowering our PUD percentage from 38% of the total reserves at December 31, 2013 to only 23% at December 31, 2014. In future years we plan to initiate a number of new CO_2 floods, including at Webster, Conroe and Cedar Creek Anticline ("CCA") fields.

In the Gulf Coast region, Hastings, Oyster Bayou and Heidelberg fields continue to show solid production growth and improved reservoir response. Tinsley Field production continues to perform strongly, although we believe production is at or near its peak. Additionally, we are reviewing our mature tertiary fields with our innovation and improvement teams and are optimistic that we can mitigate some of the production declines at those fields.

CONTINUED TERTIARY PRODUCTION GROWTH



In the Rocky Mountain region, our CCA 2014 annual production was up 14% year-over-year, primarily due to improved drilling efforts as well as waterflood performance in mature areas. Bell Creek Field tertiary production increased to over 1,800 Bbls/d at December 31, 2014 compared to 300 Bbls/d at the end of 2013, and we expect production at this field to continue to grow in 2015. Hartzog Draw Field production was up slightly for the full year as a result of our successful completion of five wells in 2014.

Our CO_2 supply and transportation operations continue to operate strongly, but we continue to look for potential optimization areas. In the Gulf Coast region, we used an average of 835 million cubic feet per day ("MMcf/d") of CO_2 (including CO_2 captured from industrial sources) for our tertiary activities during 2014. Thus far in 2015, we have completed the only well planned at Jackson Dome this year and are awaiting completion and flow tests, but early indications show that this well will be productive. In addition, our industrial source supply is expected to get a boost from the gasification and carbon capture systems at Mississippi Power's Kemper County Power Plant in the next 12 to 18 months.

In the Rocky Mountain region, we used an average of 69 MMcf/d of CO_2 during 2014 from our combined sources at LaBarge and Lost Cabin. Our innovation and improvement teams have been looking at multiple options to solve the issues at the Riley Ridge gas processing facility, including determining solutions for the sulfur deposition in the gas supply wells (together, "Riley Ridge"); however, due to such issues, we do not currently expect natural gas or helium production at Riley Ridge to resume until 2016. We continue to believe Riley Ridge will be the anchor source of CO_2 for our Rocky Mountain fields in the future.

As CO_2 EOR is increasingly being viewed as a complementary long-term strategy to reduce carbon emissions from various current and proposed industrial facilities, we continue to have ongoing discussions regarding the transport or purchase of CO_2 volumes from existing industrial plants of various types. Currently we are utilizing over 2.5 million metric tons of CO_2 annually from industrial sources for our CO_2 EOR operations that may have otherwise been released into the atmosphere. Based on information from the EPA's Greenhouse Gas Equivalencies Calculator, this amount equals the annual greenhouse gas emissions from over 500,000 passenger vehicles. Our CO_2 EOR process provides an economical and technically feasible method to develop otherwise stranded oil reserves with the added benefit of associated CO_2 storage.

On the financial front, we generated approximately $107 million of adjusted cash flow from operations in excess of our capital expenditures and dividend payments in 2014, demonstrating our commitment to strong financial discipline, as both capital and lease operating expenses came in under budget for the year. We are seeing continued improvement from our focus in 2014 on reducing costs, as evidenced by four consecutive quarters of a drop in lease operating expenses per BOE (excluding Delhi Field remediation costs, insurance reimbursements and unplanned Riley Ridge workovers). Excluding those nonrecurring items, fourth quarter operating costs averaged $22.64 per BOE, 14% lower than in the fourth quarter of 2013. In addition, we expect to receive significant incremental cash flow from our hedges in place for 2015 if the current lower oil price environment persists for the remainder of this year.

In April 2014, we issued $1.25 billion of 5½% Senior Subordinated Notes due 2022 to repurchase and redeem our 8¼% Senior Subordinated Notes due 2020 and to pay down approximately $150 million of outstanding borrowings on our bank credit facility. In December 2014, we amended and restated our bank credit facility, which provides for aggregate lender commitments of $1.6 billion and an extended termination date of the facility from May 2016 to December 2019. Together, these transactions move our long-term debt maturities further into the future while also allowing us to lock in attractive rates and reduce our out-of-pocket interest costs.

We declared quarterly cash dividends of $0.0625 per common share during each quarter of 2014, with aggregate dividends of $87.0 million, or $0.25 per common share, paid during the year ended December 31, 2014. As a result of the oil price declines, in January 2015 we announced the decision to keep our dividend payment flat for the first quarter of 2015 at the rate of $0.0625 per common share, rather than increasing it as originally planned.

On the share repurchase front, we bought back a total of 12.4 million shares of Denbury common stock for $200.4 million during the first quarter of 2014. In November 2014, we announced that our share repurchase program was being suspended in order to protect our financial health and preserve liquidity amid a period of declining oil prices and overall oil price uncertainty.

As we strive to make improvements throughout our entire company, we are cognizant of opportunities to better the lives of our employees, our environment and our communities. We believe that operating a sustainable and ethical company is essential to being a responsible corporate citizen, and have detailed our efforts to earn this distinction in our 2014 Corporate Responsibility Report. This report illustrates our commitment to these principles and to transparency with our stakeholders regarding our economic, environmental and social performance. We encourage you to review our report and provide us feedback so that we can continue to address matters that are important to our stakeholders.

We believe Denbury's business model is an excellent example of how to combine technology, economics and science to take a proven, safe process to a new level. We believe our investments, our experience and our acquired knowledge give us a strategic and competitive advantage, and we look forward to continued leadership in this arena for many years. We have built a strong team of dedicated employees with the skills and expertise to pursue our strategy, and our results are directly attributable to their efforts. We believe this dedication, paired with the support of our shareholders, will allow us to come out of this difficult economic period stronger and more prepared to deliver in 2015 and beyond.

Sincerely,

Phil Rykhoek
President and
Chief Executive Officer

March 27, 2015

BOARD OF DIRECTORS

Wieland F. Wettstein
Chairman of the Board
President
Finex Financial Corporation Ltd.
Calgary, Alberta

Michael L. Beatty
Chairman and Chief Executive Officer
Beatty & Wozniak, P.C.
Denver, Colorado [1]

Michael B. Decker
Partner
Wingate Partners
Dallas, Texas

John P. Dielwart
Vice-Chairman
ARC Financial Corp.
Calgary, Alberta

Ronald G. Greene
Principal
Tortuga Investment Corp.
Calgary, Alberta [2]

Gregory L. McMichael
Independent Consultant
Denver, Colorado

Kevin O. Meyers
Independent Consultant
Anchorage, Alaska

Phil Rykhoek
Director, President and Chief Executive Officer
Denbury Resources Inc.
Plano, Texas

Randy Stein
Independent Consultant
Denver, Colorado

Laura A. Sugg
Independent Consultant
Houston, Texas

(1) *Mr. Beatty resigned as a member of the Board of Directors effective as of March 20, 2015.*
(2) *Mr. Greene will not be standing for re-election at Denbury's 2015 Annual Meeting of the Stockholders.*

Our corporate governance guidelines, as well as the charters for our nominating/corporate governance committee; compensation committee; audit committee; reserves and health, safety and environmental committee; and risk committee can be found on the Company website at www.denbury.com. The website also contains other corporate governance information such as our code of ethics for our directors, officers and employees; our hotline number to report any areas of concern; and other data.

You may contact our board members by addressing a letter to Denbury Resources Inc., Attn: Corporate Secretary, or by email to secretary@denbury.com.

OFFICERS

Phil Rykhoek
Director, President and Chief Executive Officer

Mark C. Allen
Senior Vice President, Chief Financial Officer, Treasurer and Assistant Secretary

Jim Matthews
Senior Vice President, General Counsel and Secretary

Brad Kerr
Senior Vice President — Development, Technical and Innovation

Dan E. Cole
Vice President — Commercial Development and Governmental Relations

Matthew Dahan
Vice President — North Region

Matt Elmer
Vice President — Gulf Coast Region

John Filiatrault
Vice President — CO_2 Supply and Pipelines

Jeff Marcel
Vice President — Drilling

Steve McLaurin
Vice President and Chief Information Officer

Alan Rhoades
Vice President and Chief Accounting Officer

Whitney Shelley
Vice President and Chief Human Resources Officer

Cory Weinbel
Vice President — Projects and Facilities

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

2014 FORM 10-K

(Mark One)

✓ Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2014
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 1-12935

Denbury

DENBURY RESOURCES INC.

(Exact name of Registrant as specified in its charter)

Delaware	20-0467835
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
5320 Legacy Drive, Plano, TX	75024
(Address of principal executive offices)	*(Zip Code)*

Registrant's telephone number, including area code: (972) 673-2000

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class:	Name of Each Exchange on Which Registered:
Common Stock $.001 Par Value	New York Stock Exchange

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

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

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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 small reporting company. See the definitions of "large accelerated filer", "accelerated filer", and "small reporting company" in Rule 12-b2 of the Exchange Act.
Large accelerated filer ✓ Accelerated filer ____ Non-accelerated filer ____ Smaller reporting company ____

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

The aggregate market value of the registrant's common stock held by non-affiliates, based on the closing price of the registrant's common stock as of the last business day of the registrant's most recently completed second fiscal quarter was $6,386,671,272.

The number of shares outstanding of the registrant's Common Stock as of January 31, 2015, was 356,635,504.

DOCUMENTS INCORPORATED BY REFERENCE

Document:	Incorporated as to:
1. Notice and Proxy Statement for the Annual Meeting of Stockholders to be held May 19, 2015.	*1. Part III, Items 10, 11, 12, 13, 14*

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Glossary and Selected Abbreviations

Bbl	One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.
Bbls/d	Barrels of oil or other liquid hydrocarbons produced per day.
Bcf	One billion cubic feet of natural gas, CO_2 or helium.
BOE	One barrel of oil equivalent, using the ratio of one barrel of crude oil, condensate or natural gas liquids to 6 Mcf of natural gas.
BOE/d	BOEs produced per day.
Btu	British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit (°F).
CO_2	Carbon dioxide.
EOR	Enhanced oil recovery. In the context of our oil and natural gas production, EOR is also referred to as tertiary recovery.
Finding and development costs	The average cost per BOE to find and develop proved reserves during a given period. It is calculated by dividing (a) costs, which include the sum of (i) the total acquisition, exploration and development costs incurred during the period plus (ii) future development and abandonment costs related to the specified property or group of properties, by (b) the sum of (i) the change in total proved reserves during the period plus (ii) total production during that period.
GAAP	Accounting principles generally accepted in the United States of America.
MBbls	One thousand barrels of crude oil or other liquid hydrocarbons.
MBOE	One thousand BOEs.
Mcf	One thousand cubic feet of natural gas, CO_2 or helium at a temperature base of 60 degrees Fahrenheit (°F) and at the legal pressure base (14.65 to 15.025 pounds per square inch absolute) of the state or area in which the reserves are located or sales are made.
Mcf/d	One thousand cubic feet of natural gas, CO_2 or helium produced per day.
MMBbls	One million barrels of crude oil or other liquid hydrocarbons.
MMBOE	One million BOEs.
MMBtu	One million Btus.
MMcf	One million cubic feet of natural gas, CO_2 or helium.
MMcf/d	One million cubic feet of natural gas, CO_2 or helium per day.
Noncash fair value adjustments on commodity derivatives	The net change during the period in the fair market value of commodity derivative positions. Noncash fair value adjustments on commodity derivatives is a non-GAAP measure and makes up only a portion of "Derivatives expense (income)" in the Consolidated Statements of Operations, which also includes the impact of settlements on commodity derivatives during the period. Its use is further discussed in *Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Operating Results Table.*
NYMEX	The New York Mercantile Exchange. In the context of our oil and natural gas sales, NYMEX pricing represents the West Texas Intermediate benchmark price for crude oil and Henry Hub benchmark price for natural gas.
Probable Reserves*	Reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.
Proved Developed Reserves*	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved Reserves*	Reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.
Proved Undeveloped Reserves*	Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells, in each case where a relatively major expenditure is required.
PV-10 Value	The estimated future gross revenue to be generated from the production of proved reserves, net of estimated future production, development and abandonment costs, and before income taxes, discounted to a present value using an annual discount rate of 10%. PV-10 Values were prepared using average hydrocarbon prices equal to the unweighted arithmetic average of hydrocarbon prices on the first day of each month within the 12-month period preceding the reporting date. PV-10 Value is a non-GAAP measure and does not purport to represent the fair value of our oil and natural gas reserves; its use is further discussed in footnote 5 to the table included in Item 1, *Estimated Net Quantities of Proved Oil and Natural Gas Reserves and Present Value of Estimated Future Net Revenues – Oil and Natural Gas Reserve Estimates.*
Tcf	One trillion cubic feet of natural gas, CO_2 or helium.
Tertiary Recovery	A term used to represent techniques for extracting incremental oil out of existing oil fields (as opposed to primary and secondary recovery or "non-tertiary" recovery). In the context of our oil and natural gas production, tertiary recovery is also referred to as EOR.

* This definition is an abbreviated version of the complete definition set forth in Rule 4-10(a) of Regulation S-X. For the complete definition see: http://www.ecfr.gov/cgi-bin/retrieveECFR?gp=1&SID=6f0cbc2a2934b1576e95496863cfb7ef&ty=HTML&h=L&r=SECTION&n=se17.3.210_14_610.

Item 1. Business and Properties

GENERAL

Denbury Resources Inc., a Delaware corporation, is an independent oil and natural gas company with 437.7 MMBOE of estimated proved oil and natural gas reserves as of December 31, 2014, of which 83% is oil. Our operations are focused in two key operating areas: the Gulf Coast and Rocky Mountain regions. Our goal is to increase the value of our properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis relating to CO_2 enhanced oil recovery operations.

As part of our corporate strategy, we are committed to strong financial discipline, efficient operations and creating long-term value for our shareholders through the following key principles:

- target specific regions where we either have, or believe we can create, a competitive advantage as a result of our ownership or use of CO_2 reserves, oil fields and CO_2 infrastructure;
- secure properties where we believe additional value can be created through tertiary recovery operations and a combination of other exploitation, development, exploration and marketing techniques;
- acquire properties that give us a majority working interest and operational control or where we believe we can ultimately obtain it;
- maximize the value and cash flow generated from our operations by increasing production and reserves while controlling costs;
- optimize the timing and allocation of capital among our investment opportunities to maximize the rates of return on our investments;
- return a portion of the cash flow generated from our operations to shareholders through regular quarterly dividend payments at a sustainable rate, and strategic repurchases of our common stock made from time to time;
- exercise financial discipline by balancing our development capital expenditures and dividends with our cash flow from operations; and
- attract and maintain a highly competitive team of experienced and incentivized personnel.

Denbury has been publicly traded on the New York Stock Exchange since 1997. Our corporate headquarters is located at 5320 Legacy Drive, Plano, Texas 75024, and our phone number is 972-673-2000. At December 31, 2014, we had 1,523 employees, 813 of whom were employed in field operations or at our field offices. We make our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports, filed or furnished pursuant to section 13(a) or 15(d) of the Securities Exchange Act of 1934, available free of charge on or through our website, www.denbury.com, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The public may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website, www.sec.gov, which contains reports, proxy and information statements and other information filed by Denbury. Throughout this Annual Report on Form 10-K ("Form 10-K") we use the terms "Denbury," "Company," "we," "our," and "us" to refer to Denbury Resources Inc. and, as the context may require, its subsidiaries.

2014 BUSINESS DEVELOPMENTS

In response to the decline in oil prices during the latter part of 2014, in November 2014, we announced a significant reduction in our capital spending plans, reducing projected 2015 capital spending to $550 million, or roughly half of 2014 levels, and decreasing our estimated dividend rate for 2015 to $0.40 per common share on an annualized basis, from the previous projection of a rate ranging between $0.50 per common share to $0.60 per common share on an annualized basis. At the same time, we announced that our share repurchase program was being suspended in order to protect our financial health and preserve liquidity amid a period of declining oil prices and overall oil price uncertainty. As a result of further oil price declines in late 2014 and early 2015, in January 2015, we announced another change in our planned 2015 dividend rate, as the Company's Board of Directors declared a dividend of $0.0625 per common share for the first quarter of 2015, or $0.25 per common share on an annualized basis, a level consistent with our 2014 dividend rate.

2014 business developments also included the following:

- Increased our average tertiary oil production to 41,079 Bbls/d in 2014, a 7% increase from average tertiary oil production in 2013, primarily due to continued field development and expansion of facilities in our existing CO_2 floods at Hastings, Heidelberg, Oyster Bayou, Tinsley, and Bell Creek fields.
- Declared quarterly cash dividends of $0.0625 per common share during each quarter of 2014, with aggregate dividends of $87.0 million, or $0.25 per common share, paid during the year ended December 31, 2014.
- Repurchased a total of 12.4 million shares of Denbury common stock for $200.4 million during the first quarter of 2014.
- Reduced our interest expense by refinancing a portion of our indebtedness. In April 2014, we issued $1.25 billion of 5½% Senior Subordinated Notes due 2022. The net proceeds of approximately $1.23 billion, after issuance costs, were used to repurchase and redeem our 8¼% Senior Subordinated Notes due 2020 and to pay down approximately $150 million of outstanding borrowings on our bank credit facility.
- Amended and restated our bank credit facility, effective as of December 9, 2014, to provide for a borrowing base of $3.0 billion, aggregate lender commitments of $1.6 billion, and an extended termination date of the facility from May 2016 to December 2019.
- During the fourth quarter of 2014, we created innovation and improvement teams to evaluate each of our assets during 2015 with a goal of increasing the value of both existing assets and future projects by optimizing field operational and development plans, increasing CO_2 flood recovery efficiency and reducing costs.

OIL AND NATURAL GAS OPERATIONS

Summary. Our oil and natural gas properties are concentrated in the Gulf Coast and Rocky Mountain regions of the United States. Currently our properties with proved and producing reserves in the Gulf Coast region are situated in Mississippi, Texas, Louisiana and Alabama, and in the Rocky Mountain region are situated in Montana, North Dakota and Wyoming. Our primary focus is using CO_2 in EOR, and our current portfolio of CO_2 EOR projects provides us significant oil production and reserve growth potential in the future.

We have been conducting and expanding EOR operations on our assets in the Gulf Coast region since 1999, and as a result, we currently have many more CO_2 EOR projects in this region than in the Rocky Mountain region. In the Gulf Coast region, we own what is, to our knowledge, the region's only significant naturally occurring source of CO_2, and these large volumes of naturally occurring CO_2 have allowed us to significantly grow our production in that region. In addition to the sources of CO_2 we currently own, we purchase and use CO_2 captured from industrial sources which would otherwise be released into the atmosphere (sometimes referred to as anthropogenic, man-made or industrial-source CO_2) in our tertiary operations. These industrial sources of CO_2 help us recover additional oil from mature oil fields and, we believe, also provide an economical way to reduce atmospheric CO_2 emissions through the concurrent underground storage of CO_2 which occurs as part of our oil-producing EOR operations. We expect the amount of CO_2 we use which is captured from industrial sources to grow in the future.

Through December 31, 2014, we have invested a total of $4.1 billion in our tertiary fields in the Gulf Coast region (including acquisition costs and goodwill) and, in addition to recovering all of these costs, we have generated $1.9 billion of excess net cash flow (revenue less operating expenses and capital expenditures, excluding capital expenditures related to pipelines and CO_2 source fields). Of this total invested amount, approximately $286.9 million (7%) has been spent on fields that did not have any appreciable proved reserves at December 31, 2014. The proved oil reserves in our Gulf Coast tertiary oil fields have a year-end 2014 PV-10 Value of $4.8 billion, calculated using average 2014 NYMEX oil prices of $94.99. Including the Green Pipeline, which currently serves our Hastings and Oyster Bayou fields, we have invested a total of $2.2 billion in CO_2 pipelines and CO_2 source fields in the Gulf Coast region.

We began operations in the Rocky Mountain region in 2010 in connection with, and following, our merger with Encore Acquisition Company ("Encore"). We completed construction of the first section of the 20-inch Greencore Pipeline (our first CO_2 pipeline in the Rocky Mountain region) in late 2012, and received our first CO_2 deliveries from the ConocoPhillips-operated Lost Cabin gas plant in central Wyoming during the first quarter of 2013. We started CO_2 injections at our Bell Creek Field in Montana during the second quarter of 2013, with tertiary oil production from this field commencing in the third quarter of 2013. In addition to our current tertiary flood in the Rocky Mountain region, we currently have long-term plans to flood Hartzog Draw Field, Grieve Field, and the Cedar Creek Anticline ("CCA") with CO_2 after we perform additional non-tertiary development of these fields. CCA is a geological structure over 126 miles in length consisting of 14 different operating areas. Our Riley Ridge Field acquisition (completed in two stages) in 2010 and 2011, the acquisition of an interest in CO_2 reserves in LaBarge Field from Exxon Mobil Corporation and its wholly-owned subsidiary XTO Energy Inc. (collectively, "ExxonMobil") in 2012, and the previously mentioned deliveries from the ConocoPhillips-operated Lost Cabin gas plant are expected to provide us the CO_2 necessary for our current inventory of CO_2 EOR projects in the Rocky Mountain region.

Field Summary Table. The following table provides a summary by field and region of selected proved oil and natural gas reserve information, including total proved reserve quantities and the associated PV-10 Value of those reserves as of December 31, 2014, and average daily production for 2014, all based on Denbury's net revenue interest ("NRI"). The reserve estimates for all years presented were prepared by DeGolyer and MacNaughton ("D&M"), independent petroleum engineers located in Dallas, Texas. We serve as operator of virtually all of our significant properties, in which we also own most of the interests, although typically less than a 100% working interest, and a lesser NRI due to royalties and other burdens. For additional oil and natural gas reserves information, see *Estimated Net Quantities of Proved Oil and Natural Gas Reserves and Present Value of Estimated Future Net Revenues* below.

	Proved Reserves as of December 31, 2014[1]					2014 Average Daily Production		
	Oil (MBbls)	Natural Gas (MMcf)	MBOEs	% of Company Total MBOEs	PV-10 Value[2] (000's)	Oil (Bbls/d)	Natural Gas (Mcf/d)	Average 2014 NRI
Tertiary oil properties								
Gulf Coast region								
Mature properties:								
Brookhaven	8,373	—	8,373	1.9%	$ 254,190	1,759	—	81.4%
Eucutta	6,853	—	6,853	1.6%	161,070	2,137	—	83.6%
Mallalieu	5,083	—	5,083	1.2%	178,238	1,799	—	78.1%
Other mature properties [3]	19,813	—	19,813	4.5%	425,246	6,122	—	71.7%
Total mature properties	40,122	—	40,122	9.2%	1,018,744	11,817	—	75.9%
Delhi [4]	27,573	—	27,573	6.3%	546,648	4,340	—	74.0%
Hastings	41,687	—	41,687	9.5%	1,039,419	4,777	—	79.9%
Heidelberg	33,170	—	33,170	7.5%	904,021	5,707	—	80.8%
Oyster Bayou	13,413	—	13,413	3.1%	508,243	4,683	—	87.0%
Tinsley	22,648	—	22,648	5.2%	829,163	8,507	—	81.4%
Total Gulf Coast region	178,613	—	178,613	40.8%	4,846,238	39,831	—	79.1%
Rocky Mountain region								
Bell Creek	36,505	—	36,505	8.3%	721,717	1,248	—	83.6%
Total Rocky Mountain region	36,505	—	36,505	8.3%	721,717	1,248	—	83.6%
Total tertiary properties	215,118	—	215,118	49.1%	5,567,955	41,079	—	79.3%
Non-tertiary oil and gas properties								
Gulf Coast region								
Mississippi	2,932	35,376	8,828	2.0%	112,754	1,093	7,350	30.9%
Texas	24,462	18,632	27,567	6.3%	625,952	5,384	5,436	80.7%
Other	6,033	3,301	6,583	1.6%	99,359	976	514	29.1%
Total Gulf Coast region	33,427	57,309	42,978	9.9%	838,065	7,453	13,300	53.6%
Rocky Mountain region								
Cedar Creek Anticline [5]	103,886	15,839	106,526	24.3%	2,099,653	18,488	2,073	81.0%
Riley Ridge	—	367,516	61,253	14.0%	27,606	—	968	79.7%
Other	9,904	11,738	11,860	2.7%	214,790	3,586	6,614	38.8%
Total Rocky Mountain region	113,790	395,093	179,639	41.0%	2,342,049	22,074	9,655	68.9%
Total non-tertiary properties	147,217	452,402	222,617	50.9%	3,180,114	29,527	22,955	63.9%
Company Total	362,335	452,402	437,735	100.0%	$8,748,069	70,606	22,955	72.1%

(1) The above reserve estimates were prepared in accordance with Financial Accounting Standards Board Codification ("FASC") Topic 932, *Extractive Industries – Oil and Gas,* using the arithmetic average of the first-day-of-the-month NYMEX commodity price for each month during 2014, which were $94.99 per Bbl for crude oil and $4.30 per MMBtu for natural gas, both of which were adjusted for market differentials by field. This prescribed methodology does not reflect significant crude oil price declines in late 2014 and early 2015, when oil prices dropped rapidly, declining to below $45 per Bbl in January 2015. Sustained prices at these recent levels would result in a significant decrease in our PV-10 Value, and to a lesser degree, a reduction in our proved reserve volumes.

(2) PV-10 Value is a non-GAAP measure and is different from the GAAP measure, the Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure"), in that PV-10 Value is a pre-tax number and the Standardized Measure is an after-tax number. The Standardized Measure was $5.9 billion at December 31, 2014. A comparison of PV-10 Value to the Standardized Measure is included in the reserves table in *Estimated Net Quantities of Proved Oil and Natural Gas Reserves and Present Value of Estimated Future Net Revenues* below. The information used to calculate PV-10 Value is derived directly from data determined in accordance with FASC Topic 932. See the definition of PV-10 Value in the *Glossary and Selected Abbreviations*.

(3) Other mature properties include Cranfield, Little Creek, Martinville, McComb and Soso fields in Mississippi and Lockhart Crossing Field in Louisiana.

(4) The foregoing Delhi Field reserve quantities, values and average daily production reflect the reversionary assignment of approximately 25% of our interest in that field effective November 1, 2014. The effectiveness, timing, and scope of the reversionary assignment are subject to ongoing litigation, the ultimate outcome of which cannot be predicted.

(5) The Cedar Creek Anticline consists of a series of 14 different operating areas.

Enhanced Oil Recovery Overview. CO_2 used in EOR is one of the most efficient tertiary recovery mechanisms for producing crude oil. When injected under pressure into underground, oil-bearing rock formations, CO_2 acts somewhat like a solvent as it travels through the reservoir rock, mixing with and modifying the characteristics of the oil so it can be produced and sold. The terms "tertiary flood," "CO_2 flood" and "CO_2 EOR" are used interchangeably throughout this document.

While enhanced oil recovery projects utilizing CO_2 have been successfully performed by numerous oil and gas companies in a wide range of oil-bearing reservoirs in different oil-producing basins, we believe our investments, experience and acquired knowledge give us a strategic and competitive advantage in the areas in which we operate. We apply what we have learned and developed over the years to improve and increase sweep efficiency within the CO_2 EOR projects we operate.

We began our CO_2 operations in August 1999, when we acquired Little Creek Field, followed by our acquisition of Jackson Dome CO_2 reserves and the NEJD pipeline in 2001. Based upon our success at Little Creek and the ownership of the CO_2 reserves, we began to transition our capital spending and acquisition efforts to focus more heavily on CO_2 EOR and, over time, transformed our strategy to focus primarily on owning and operating oil fields that are well suited for CO_2 EOR projects. Prior to tertiary flooding, we strive to maximize the currently sizeable primary and secondary production from our prospective tertiary fields and from fields in which tertiary floods have commenced but still contain significant non-tertiary production. Our asset base today almost entirely consists of, or otherwise relates to, oil fields that we are currently flooding with CO_2 or plan to flood with CO_2 in the future, or assets that produce CO_2.

Our tertiary operations have grown so that (1) 49% of our proved reserves at December 31, 2014 are proved tertiary oil reserves; (2) 55% of our 2014 production was related to tertiary oil operations (on a BOE basis); and (3) 75% of our 2014 capital expenditures (excluding acquisitions) were related to our tertiary oil operations. At year-end 2014, the proved oil reserves in our tertiary recovery oil fields had an estimated PV-10 Value of approximately $5.6 billion, or 64% of our total PV-10 Value. In addition, there are significant probable and possible reserves at several other fields for which tertiary operations are underway or planned.

Although the up-front cost of tertiary production infrastructure and time to construct pipelines and production facilities is greater than in primary oil recovery, we believe tertiary recovery has several favorable, offsetting and unique attributes, including (1) a lower exploration risk, as we are operating oil fields that have significant historical production and reservoir and geological data, (2) an industry-competitive rate of return at relatively low oil prices, depending on the specific field and area, (3) limited competition for this recovery method in our geographic regions, (4) our EOR operations are generally less disruptive to new habitats in comparison to other oil and natural gas development because we further develop existing (as opposed to new) oil fields, and (5) through our oil-producing EOR operations, we concurrently store CO_2 captured from industrial sources in the same underground formations that previously trapped and stored oil and natural gas.

2015 Development Plan. In the fourth quarter of 2014, we announced that we were undertaking development plan changes and operational initiatives in light of the late-2014 significant oil price declines and uncertainty around future oil prices. These changes included reducing budgeted 2015 capital spending to a level at which we believe we can maintain production relatively flat with average 2014 levels, while slowing the development pace of certain fields. During this period of reduced capital spending, the recently-created innovation and improvement teams are evaluating each of our assets with a goal of increasing the value of both existing assets and future projects by optimizing field operational and development plans, increasing CO_2 flood recovery efficiency and reducing costs. These initiatives aim to increase the profitability of our assets, making them more resilient to lower oil prices. We will continue to evaluate the timing of development of our inventory of fields and related pipelines and facilities, which will be largely dependent upon commodity prices and CO_2 availability. Therefore, planned development activities presented in the discussions that follow may be delayed or modified depending primarily upon oil prices and our level of cash flow to fund such development, as well as the availability of CO_2.

Tertiary Oil Properties

Gulf Coast Region

CO_2 Sources and Pipelines

Jackson Dome. Our primary Gulf Coast CO_2 source, Jackson Dome, located near Jackson, Mississippi, was discovered during the 1970s by oil and gas companies that were exploring for hydrocarbons. This large and relatively pure source of naturally occurring CO_2 (98% CO_2) is, to our knowledge, the only significant underground deposit of CO_2 in the United States east of the Mississippi River. Together with the related CO_2 pipeline infrastructure, Jackson Dome provides us a significant strategic advantage in the acquisition of properties in Mississippi, Louisiana and southeastern Texas that are well suited for CO_2 EOR.

We acquired Jackson Dome in February 2001 in a purchase that also gave us ownership and control of the NEJD CO_2 pipeline and provided us with a reliable supply of CO_2 at a reasonable and predictable cost for our Gulf Coast CO_2 tertiary recovery operations. Since February 2001, we have acquired and drilled numerous CO_2-producing wells, significantly increasing our estimated proved Gulf Coast CO_2 reserves from approximately 800 Bcf at the time of acquisition of Jackson Dome to approximately 5.7 Tcf as of December 31, 2014. The CO_2 reserve estimates are based on a gross working interest of the CO_2 reserves, of which our net revenue interest is approximately 4.5 Tcf, and is included in the evaluation of proved CO_2 reserves prepared by D&M, an independent petroleum engineering consulting firm. In discussing our available CO_2 reserves, we make reference to the gross amount of proved and probable reserves, as this is the amount that is available both for our own tertiary recovery programs and for industrial users who are customers of Denbury and others, as we are responsible for distributing the entire CO_2 production stream.

In addition to our proved reserves, we estimate that we have 2.1 Tcf of probable CO_2 reserves at Jackson Dome. While the majority of these probable reserves are located in structures that have been drilled and tested, such reserves are still considered probable reserves because (1) the original well is plugged; (2) they are located in fault blocks that are immediately adjacent to fault blocks with proved reserves; or (3) they are reserves associated with increasing the ultimate recovery factor from our existing reservoirs with proved reserves. In addition, a significant portion of these probable reserves at Jackson Dome are located in undrilled structures where we have sufficient subsurface and seismic data indicating geophysical attributes that, coupled with our historically high drilling success rate, provide a reasonably high degree of certainty that CO_2 is present.

Although our current proved CO_2 reserves are sizeable, in order to continue our tertiary development of oil fields in the Gulf Coast region, incremental deliverability of CO_2 is required. In order to obtain additional CO_2 deliverability, we have conducted several 3D seismic surveys in the Jackson Dome area over the past several years and anticipate drilling one development well in 2015 that is intended to increase the area's productive capacity.

In addition to our drilling at Jackson Dome, we continue to expand our processing and dehydration capacities, and we continue to install pipelines and/or pumping stations necessary to transport the CO_2 through our controlled pipeline network. We expect our current proved reserves of CO_2, coupled with a risked drilling program at Jackson Dome and CO_2 expected to be captured from industrial sources, to provide sufficient quantities of CO_2 for us to develop our proved and probable EOR reserves in the Gulf Coast region. In the future, we believe that once a CO_2 flood in a field reaches its productive economic limit, we could recycle a portion of the CO_2 that remains in that field's reservoir and utilize it for oil production in another field's tertiary flood.

In the Gulf Coast region, approximately 91% of our average daily CO_2 produced from Jackson Dome or captured from industrial sources in 2014, 2013 and 2012 was used in our tertiary recovery operations, with the balance delivered to third-party industrial users. During 2014, we used an average of 835 MMcf/d of CO_2 (including CO_2 captured from industrial sources) for our tertiary activities.

Gulf Coast CO_2 Captured from Industrial Sources. In addition to our natural source of CO_2, we are currently party to three long-term contracts to purchase CO_2 from industrial plants. We currently purchase CO_2 from an industrial facility in Port Arthur, Texas and from an industrial facility in Geismar, Louisiana, and we anticipate taking deliveries in 2016 from Mississippi Power's Kemper County Energy Facility. We estimate these sources will supply, in the aggregate, approximately 185 MMcf/d of CO_2 to our EOR operations, although under certain circumstances they could provide higher or lower volumes. Additionally, we are in ongoing discussions with other parties who have plans to construct plants near the Green Pipeline.

In addition to the potential CO_2 sources discussed above, we continue to have ongoing discussions with owners of existing plants of various types that emit CO_2 that we may be able to purchase and/or transport. In order to capture such volumes, we (or the plant owner) would need to install additional equipment, which includes, at a minimum, compression and dehydration facilities. Most of these existing plants emit relatively small volumes of CO_2, generally less than our contracted sources, but such volumes may still be attractive if the source is located near CO_2 pipelines. The capture of CO_2 could also be influenced by potential federal legislation, which could impose economic penalties for atmospheric CO_2 emissions. We believe that we are a likely purchaser of CO_2 captured in our areas of operation because of the scale of our tertiary operations and our CO_2 pipeline infrastructure.

Gulf Coast CO_2 Pipelines. We acquired the 183-mile NEJD CO_2 pipeline that runs from Jackson Dome to near Donaldsonville, Louisiana, as part of the 2001 acquisition of our Jackson Dome CO_2 source. Since 2001, we have acquired or constructed nearly 755 miles of CO_2 pipelines, and as of December 31, 2014, we have access to over 950 miles of CO_2 pipelines, which gives us the ability to deliver CO_2 throughout the Gulf Coast region. In addition to the NEJD CO_2 pipeline, the major pipelines in the Gulf Coast region are the Free State Pipeline (90 miles), the Delta Pipeline (110 miles), the Green Pipeline Texas (120 miles), and the Green Pipeline Louisiana (200 miles).

Completion of the Green Pipeline allowed for the first CO_2 injection into Hastings Field, located near Houston, Texas, in 2010, and gives us the ability to deliver CO_2 to oil fields all along the Gulf Coast from Baton Rouge, Louisiana, to Alvin, Texas. At the present time, most of the CO_2 flowing in the Green Pipeline is delivered from the Jackson Dome area, but we began receiving CO_2 from an industrial facility in Port Arthur, Texas in 2012, and are currently transporting a third party's CO_2 for a fee to the sales point at Hastings Field. In addition, we began receiving CO_2 from an industrial facility in Geismar, Louisiana in 2013. We expect the volume of CO_2 transported through the Green Pipeline to increase in future years as we develop our inventory of CO_2 EOR projects in this area.

Tertiary Properties with Tertiary Production and Proved Tertiary Reserves at December 31, 2014

Mature properties. Mature properties include our longest-producing properties which are generally located along our NEJD CO_2 pipeline in southwest Mississippi and Louisiana and our Free State Pipeline in east Mississippi. This group of properties includes our initial CO_2 field, Little Creek, as well as several other fields (Brookhaven, Cranfield, Eucutta, Lockhart Crossing, Mallalieu, Martinville, McComb and Soso fields). These fields accounted for 29% of our total 2014 CO_2 EOR production and approximately 19% of our year-end proved tertiary reserves. These fields have been producing for some time, and their production is generally declining. Many of these fields contain multiple reservoirs that are amenable to CO_2 EOR. In 2015, we currently plan to invest approximately $20 million to further develop our mature tertiary properties.

From the time we originally acquired these properties through December 31, 2014, we have recovered all of our tertiary investment relating to our mature properties, and the excess net cash flow (revenue less operating expenses and capital expenditures, including the acquisition costs) from these mature properties through that date was $2.1 billion. As of December 31, 2014, the estimated PV-10 Value of our mature properties was $1.0 billion.

Delhi Field. Delhi Field is located east of Monroe, Louisiana. In May 2006, we purchased our initial interest in Delhi for $50 million, plus an approximate 25% reversionary interest to the seller after we receive $200 million in "total net cash flow," as defined in the applicable agreements between the parties. We began well and facility development in 2008 and began delivering CO_2 to the field in the fourth quarter of 2009 via the Delta Pipeline, which runs from Tinsley Field to Delhi Field.

First tertiary production occurred at Delhi Field in the first quarter of 2010. Production from Delhi Field in the fourth quarter of 2014 averaged 3,743 Bbls/d, down from 4,793 Bbls/d in the fourth quarter of 2013. The primary reason for this comparative fourth quarter decline is the November 1, 2014, reversionary assignment to the seller of the field of approximately 25% of our interest in Delhi Field. The effectiveness, timing, and scope of the reversionary assignment are subject to ongoing litigation, the ultimate outcome of which cannot be predicted.

Additionally, our development of Delhi Field has been impacted by a release of well fluids within an area of Delhi Field occurring in the second quarter of 2013 and our subsequent remediation of such release. During the years ended December 31, 2014 and 2013, we recorded $16.8 million and $114.0 million, respectively, of lease operating expenses related to this release and its remediation in our Consolidated Statements of Operations, bringing our total cost estimate to date with respect to these expenses to $130.8 million. We received a $25.0 million cost reimbursement ($23.9 million net to Denbury) in October 2014 related to the Delhi Field release and remediation from our insurance carrier providing the first layer of our excess insurance coverage, which was recognized as a reduction to lease operating expenses for the year ended December 31, 2014. See Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Insurance Recoveries to Cover Costs of 2013 Delhi Field Release* and Note 11, *Commitments and Contingencies* to the Consolidated Financial Statements for further discussion of these matters. We currently plan to invest approximately $30 million to $50 million in this field during 2015, primarily related to a natural gas liquids extraction plant, which we anticipate will be placed into service in the second half of 2016. This plant will provide us with the ability to sell natural gas liquids from the produced stream, improve the efficiency of the flood, and utilize extracted methane to power the plant and reduce field operating expenses.

From inception through December 31, 2014, we had not yet recovered our tertiary investment in this field, and the remaining investment to be recovered (revenue less operating expenses and capital expenditures, including acquisition costs) from Delhi Field was $12 million. As of December 31, 2014, the estimated PV-10 Value of Delhi Field was $546.6 million.

Hastings Field. Hastings Field is located south of Houston, Texas. We acquired a majority interest in this field in February 2009 for $247 million. We initiated CO_2 injection in the West Hastings Unit during the fourth quarter of 2010 upon completion of the construction of the Green Pipeline. Due to the large vertical oil column that exists in the field, we are developing the Frio reservoir using dedicated CO_2 injection and producing wells for each of the major sand intervals. We began producing oil from our EOR operations at Hastings Field in the first quarter of 2012, and we booked initial proved tertiary reserves for the West Hastings Unit in 2012. In 2015, we will begin employing a new series flood approach to certain portions of this field. The series flood includes CO_2 flooding one zone at a time and moving up the reservoir, which we believe will enhance the overall efficiency of the flood, and may also be applied in the future to other fields with appropriate reservoir characteristics. During the fourth quarter of 2014, tertiary production from Hastings Field averaged 4,811 Bbls/d, compared to 4,270 Bbls/d in the fourth quarter of 2013. We currently plan to invest approximately $25 million in 2015 to continue to expand our development and implement the series flood at Hastings Field.

From inception through December 31, 2014, we had not yet recovered our tertiary investment in this field, and the remaining investment to be recovered (revenue less operating expenses and capital expenditures, including the acquisition cost) from Hastings Field was $333 million. As of December 31, 2014, the estimated PV-10 Value of Hastings Field was $1.0 billion.

Heidelberg Field. Heidelberg Field is located in Mississippi and consists of an East Unit and a West Unit. Construction of the CO_2 facility, connecting pipeline and well work commenced on the West Heidelberg Unit during 2008, with our first CO_2 injections into the Eutaw zone in the fourth quarter of 2008. Our first tertiary oil production occurred in the second quarter of 2009, and we began flooding the Christmas and Tuscaloosa zones in 2013 and 2014, respectively. During the fourth quarter of 2014, tertiary production at Heidelberg Field averaged 6,164 Bbls/d, compared to 5,206 Bbls/d in the fourth quarter of 2013. In 2015, we currently plan to invest approximately $45 million to continue developing the East and West Heidelberg Units, including an expansion of our Tuscaloosa development and Christmas zone and adjustments to our CO_2 floods of existing zones to better direct the CO_2 through the zones and optimize oil recovery from the field.

From inception through December 31, 2014, we have recovered all of our tertiary investment relating to the CO_2 flood at Heidelberg Field, and the excess net cash flow (revenue less operating expenses and capital expenditures, including the acquisition costs) from the field was $14 million. As of December 31, 2014, the estimated PV-10 Value of Heidelberg Field was $904.0 million.

Oyster Bayou Field. We acquired a majority interest in Oyster Bayou Field in 2007. The field is located in southeast Texas, east of Galveston Bay, and is somewhat unique when compared to our other CO_2 EOR projects because the field covers a relatively small area of 3,912 acres. We began CO_2 injections into Oyster Bayou Field in the second quarter of 2010, commenced tertiary production in the fourth quarter of 2011 from the Frio A-1 zone, and booked initial proved tertiary reserves for the field in 2012. In 2014, we completed development of the Frio A-2 zone and currently expect peak production from the field to occur in 2015. During the fourth quarter of 2014, tertiary production at Oyster Bayou Field averaged 5,638 Bbls/d, compared to 3,869 Bbls/d in the fourth quarter of 2013. In 2015, we currently plan to invest approximately $10 million to complete minor facility and conformance work.

From inception through December 31, 2014, we had not yet recovered our tertiary investment in this field, and the remaining investment to be recovered (revenue less operating expenses and capital expenditures, including the acquisition costs) from Oyster Bayou Field was $29 million. As of December 31, 2014, the estimated PV-10 Value of Oyster Bayou Field was $508.2 million.

Tinsley Field. We acquired Tinsley Field in 2006. This Mississippi field was discovered and first developed in the 1930s and is separated by different fault blocks. As is the case with the majority of fields in Mississippi, Tinsley Field produces from multiple reservoirs. Our CO_2 enhanced oil recovery operations at Tinsley Field have thus far targeted the Woodruff formation, although there is additional potential in the Perry sandstone and other smaller reservoirs. We commenced tertiary oil production from Tinsley Field in the second quarter of 2008, substantially completed development of the Woodruff formation by the end of 2014, and currently expect production to peak and begin declining in 2015. During the fourth quarter of 2014, the average tertiary oil production was 8,767 Bbls/d, compared to 7,809 Bbls/d in the fourth quarter of 2013. In 2015, we currently plan to invest approximately $10 million to minimize production declines at the field.

From inception through December 31, 2014, we have recovered all of our tertiary investment relating to the CO_2 flood at this field, and our tertiary operations at Tinsley Field have generated excess net cash flow (revenue less operating expenses and capital expenditures, including the acquisition costs) of $502 million. As of December 31, 2014, the estimated PV-10 Value of Tinsley Field was $829.2 million.

Future Tertiary Properties with No Tertiary Production or Proved Tertiary Reserves at December 31, 2014

Webster Field. We acquired our interest in Webster Field in the fourth quarter of 2012 as part of the sale and exchange transaction with ExxonMobil under which we sold to ExxonMobil our Bakken area assets in North Dakota and Montana in exchange for (1) $1.3 billion in cash, (2) operating interests in Hartzog Draw and Webster fields in Wyoming and Texas, respectively, and (3) an overriding royalty interest equivalent to an approximate one-third ownership interest in ExxonMobil's CO_2 reserves in LaBarge Field in Wyoming (the "Bakken Exchange Transaction"). The field is located in Texas, approximately eight miles northeast of our Hastings Field which we are currently flooding with CO_2. At December 31, 2014, Webster Field had estimated proved non-tertiary reserves of approximately 3.0 MMBOE, net to our interest. During the fourth quarter of 2014, non-tertiary production at Webster Field averaged 1,121 BOE/d, compared to 1,036 BOE/d in the fourth quarter of 2013. Webster Field is geologically similar to our Hastings Field, producing oil from the Frio zone at similar depths; as a result, we believe it is well suited for CO_2 EOR. In 2014, we completed a nine-mile lateral between the Green Pipeline and Webster Field, which will eventually deliver CO_2 to the field. In 2015, we currently plan to invest approximately $55 million on well work and field facilities, as well as on initial construction of a CO_2 recycle facility for the East Fault Block. We currently expect to commence CO_2 injections at Webster Field in 2016, with first tertiary production expected in 2017, the timing of which could be delayed depending on future oil prices.

Conroe Field. Conroe Field, our largest potential tertiary flood in the Gulf Coast region, is located north of Houston, Texas. We acquired a majority interest in this field in 2009 for $271 million in cash and 11.6 million shares of Denbury common stock, for a total aggregate value of $439 million. Conroe Field had estimated proved non-tertiary reserves of approximately 12.3 MMBOE at December 31, 2014, net to our interest, all of which are proved developed. During the fourth quarter of 2014, production at Conroe Field averaged 3,386 BOE/d, compared to 2,697 BOE/d in the fourth quarter of 2013, with the production increase due primarily to performing recompletions and upgrades in 2014.

Given the size of the Conroe Field (approximately 20,000 acres), the volume of CO_2 that could be injected is quite sizable and much larger than any field we have developed to date. Therefore, the pace of development will be dictated in part by the amount of available CO_2.

A pipeline must be constructed so that CO_2 can be delivered to Conroe Field. This pipeline, which is planned as an extension of our Green Pipeline, is preliminarily estimated to cover approximately 90 miles at a cost of approximately $220 million. We currently expect that over the next five years we will begin construction of this pipeline and prepare to commence CO_2 injections at Conroe Field, the timing of which may change depending on future oil prices.

Thompson Field. We acquired our interest in Thompson Field in June 2012 for $366 million. The field is located in Texas, approximately 18 miles west of our Hastings Field. Thompson Field had estimated proved non-tertiary reserves of approximately 10.2 MMBOE at December 31, 2014, net to our interest, of which approximately 77% is proved developed. During the fourth quarter of 2014, non-tertiary production at Thompson Field averaged 1,556 BOE/d net to our interest, compared to 1,331 BOE/d in the fourth quarter of 2013. Thompson Field is geologically similar to Hastings Field, producing oil from the Frio zone at similar depths, and we therefore believe it has CO_2 EOR potential. Under the terms of the Thompson Field acquisition agreement, after the initiation of CO_2 injection, the seller will retain approximately a 5% gross revenue interest (less severance taxes) once average monthly oil production exceeds 3,000 Bbls/d. The timing of CO_2 injections at Thompson Field is currently scheduled more than five years in the future, the ultimate timing of which is primarily dependent upon future oil prices.

Rocky Mountain Region

CO_2 Sources and Pipelines

LaBarge Field. We acquired an overriding royalty interest equivalent to an approximate one-third ownership interest in ExxonMobil's CO_2 reserves in LaBarge Field in the fourth quarter of 2012 as part of the Bakken Exchange Transaction. Our interest at Riley Ridge (discussed below) is also produced from the LaBarge Field. LaBarge Field is located in southwestern Wyoming.

During 2014, we received an average of approximately 40 MMcf/d of CO_2 from ExxonMobil's Shute Creek gas processing plant at LaBarge Field. Based on current capacity, and subject to availability of CO_2, we currently expect to ultimately receive up to 115 MMcf/d of CO_2 by 2021 from such plant. We pay ExxonMobil a fee to process and deliver the CO_2, which we use in our Rocky Mountain region CO_2 floods. As of December 31, 2014, our interest in LaBarge Field consisted of approximately 1.2 Tcf of proved CO_2 reserves.

Riley Ridge. The Riley Ridge Federal Unit is also located in southwestern Wyoming and produces gas from the same LaBarge Field. In a series of two acquisitions in 2010 and 2011, we acquired 100% of the operating interests in Riley Ridge, as well as a gas processing facility that was under construction at the time of purchase, for $347 million. The gas processing facility separates helium and natural gas from the gas stream. During construction of the gas processing facility, we encountered issues related to contractor performance and design failure that resulted in significant delays and incremental costs to complete the facility. We placed the gas processing facility into service during the fourth quarter of 2013 and were successful in running the facility for part of 2014, but encountered additional issues in 2014, which kept the facility from running at optimum levels, as well as additional problems associated with sulfur build-up in the gas supply wells. We are currently working to correct and remedy these issues; however, we currently expect natural gas production at Riley Ridge will remain shut-in due to such issues until 2016.

As of December 31, 2014, our interest in Riley Ridge and minor surrounding acreage contained net proved reserves of 368 Bcf (61 MMBOE) of natural gas and 1.8 Tcf of CO_2 reserves. The gas composition is approximately 65% CO_2, approximately 16% to 18% methane, less than one percent helium, and the remainder various other gases. The CO_2 reserve estimates are based on the gross working interest of the CO_2 reserves, in which our net revenue interest is approximately 1.4 Tcf. The helium reserves at Riley Ridge are owned primarily by the U.S. government; however, we have the right to produce and sell the helium reserves to a third party on behalf of the government. In exchange for this right, we pay the U.S. government a fee that fluctuates based upon realized sales proceeds. Our helium extraction agreement with the U.S. government has a minimum term extending 20 years from first production and continuing thereafter until either party terminates the contract. Reserve volumes presented herein assume that the term of this helium extraction agreement continues beyond 20 years, given the benefit to both parties to the agreement. As of December 31, 2014, we estimate that Riley Ridge contains proved helium reserves of 13.2 Bcf, which volume estimate is reduced to reflect the related fee we will remit to the U.S. government. In addition, we believe there is significant CO_2 reserve potential in other acreage surrounding Riley Ridge in which we also own an interest.

Initially, the gas processing facility at Riley Ridge was designed to separate for sale the natural gas and helium from the full well stream, with the remaining gases, principally CO_2, re-injected into the producing formation or a deeper formation. Ultimately, our primary purpose for acquiring Riley Ridge was to gain a source of CO_2 to utilize in flooding our fields in the Rocky Mountain region. We intend to construct a CO_2 capture facility and will start to use CO_2 from Riley Ridge following completion of the capture facility and planned CO_2 pipeline connecting Riley Ridge to our existing Greencore Pipeline, the timing of which is largely dependent upon future oil prices and prioritization of development activities.

Other Rocky Mountain CO_2 Sources. We began purchasing and receiving CO_2 from the ConocoPhillips-operated Lost Cabin gas plant in central Wyoming in the first quarter of 2013, under a contract that provides us as much as 50 MMcf/d of CO_2 for use in our Rocky Mountain region CO_2 floods. Our volumes received from the plant averaged approximately 29 MMcf/d in 2014.

Greencore Pipeline. The 20-inch Greencore Pipeline in Wyoming is the first CO_2 pipeline we have constructed in the Rocky Mountain region. We plan to use the pipeline as our trunk line in the Rocky Mountain region, eventually connecting our various Rocky Mountain region CO_2 sources (see *Rocky Mountain Region CO_2 Sources and Pipelines* above) to the Cedar Creek Anticline in eastern Montana and western North Dakota. The initial 232-mile section of the Greencore Pipeline begins at the ConocoPhillips-operated Lost Cabin gas plant in Wyoming and terminates at Bell Creek Field in Montana. We completed construction of this section of the pipeline in the fourth quarter of 2012 and received our first CO_2 deliveries from the ConocoPhillips-operated Lost Cabin gas plant during the first quarter of 2013. During the first quarter of 2014, we completed construction of an interconnect between our Greencore Pipeline and an existing third-party CO_2 pipeline in Wyoming, which enables us to transport CO_2 from LaBarge Field to our Bell Creek Field.

Tertiary Properties with Tertiary Production and Proved Tertiary Reserves at December 31, 2014

Bell Creek Field. Bell Creek Field is located in southeast Montana, and we acquired our interest in this field as part of the Encore merger in 2010. The oil-producing reservoir in Bell Creek Field is a sandstone reservoir with characteristics similar to those we have successfully flooded with CO_2 in the Gulf Coast region. We began first CO_2 injections into Bell Creek Field during the second quarter of 2013, recorded our first tertiary oil production in the third quarter of 2013, and booked initial proved tertiary reserves in the fourth quarter of 2013. Tertiary production, net to our interest, during the fourth quarter of 2014 averaged 1,659 Bbls/d of oil, compared to 177 Bbls/d in the fourth quarter of 2013, as production has steadily grown from the initial production response in the third quarter of 2013. We expect production from this field will continue to increase for several years. In 2015, we plan to invest approximately $55 million to expand our CO_2 flood at Bell Creek Field.

From inception through December 31, 2014, we had not yet recovered our tertiary investment in this field, and the remaining investment to be recovered (revenue less operating expenses and capital expenditures, including the acquisition costs) from Bell Creek Field was $490 million. As of December 31, 2014, the estimated PV-10 Value of Bell Creek Field was $721.7 million.

Future Tertiary Properties with No Tertiary Production or Proved Tertiary Reserves at December 31, 2014

Cedar Creek Anticline. CCA is the largest potential EOR property that we own and currently our largest producing property, contributing approximately 25% of our 2014 total production. The field is primarily located in Montana but covers such a large area (approximately 126 miles) that it also extends into North Dakota. CCA is a series of 14 different operating areas, each of which could be considered a field by itself. We acquired our initial interest in CCA as part of the Encore merger in 2010 and acquired additional interests (the "CCA Acquisition") from a wholly-owned subsidiary of ConocoPhillips in the first quarter of 2013, adding 42.2 MMBOE of incremental proved reserves at that date. See Note 2, *Acquisition,* to the Consolidated Financial Statements for further discussion of this transaction. Production from CCA, net to our interest, averaged 18,553 BOE/d during the fourth quarter of 2014, compared to production during the fourth quarter of 2013 of 18,601 BOE/d. The non-tertiary proved reserves associated with CCA were 103.9 MMBbls of oil and 15.8 Bcf of gas as of December 31, 2014.

CCA is located approximately 110 miles north of Bell Creek Field, and we currently expect to ultimately connect this field to our Greencore Pipeline. In 2015, we plan to invest approximately $50 million to improve waterfloods, drill infill development wells, and complete an environmental impact study for CO_2 development permitting. Our current plan for initiating a CO_2 flood at CCA is scheduled more than five years from now, the timing of which may change depending on future oil prices.

Hartzog Draw Field. We acquired our interest in Hartzog Draw Field in the fourth quarter of 2012 as part of the Bakken Exchange Transaction. The field is located in the Powder River Basin of northeastern Wyoming, approximately 12 miles from our Greencore Pipeline. Hartzog Draw Field had estimated proved reserves of approximately 5.0 MMBOE at December 31, 2014, net to our interest, 1.5 MMBOE of which relate to the natural gas producing Big George coal zone. During the fourth quarter of 2014, non-tertiary production averaged 2,639 BOE/d, compared to 2,204 BOE/d in the fourth quarter of 2013. We successfully completed 5 wells in Hartzog Draw Field in 2014; however, we have temporarily suspended the non-tertiary development of Hartzog Draw Field in light of the recent oil price environment. We will continue to evaluate future development opportunities and plan to continue development of the Shannon formation if prices return to higher levels that provide an acceptable rate of return. We believe the oil reservoir characteristics of Hartzog Draw Field make it well suited for CO_2 EOR in the future. We must obtain regulatory approval and construct a CO_2 pipeline from our existing Greencore Pipeline to Hartzog Draw Field before we can commence our planned CO_2 EOR project. We currently plan to commence CO_2 injections at Hartzog Draw more than five years from now, the timing of which is dependent on future oil prices.

Other Non-Tertiary Oil Properties

Despite the majority of our oil and natural gas properties discussed above consisting of either existing or planned future tertiary floods, we do also produce oil and natural gas either from fields in both our Gulf Coast and Rocky Mountain regions that are not amenable to EOR or from specific reservoirs (within an existing tertiary field) that are not amenable to EOR. For example, at Heidelberg Field, we produce natural gas from the Selma Chalk reservoir, which is separate from the Christmas and Eutaw reservoirs currently being flooded with CO_2. Production from these other non-tertiary properties totaled 5,747 BOE/d during the fourth quarter of 2014, compared to 6,994 BOE/d during the fourth quarter of 2013.

OIL AND GAS ACREAGE, PRODUCTIVE WELLS AND DRILLING ACTIVITY

In the data below, "gross" represents the total acres or wells in which we own a working interest and "net" represents the gross acres or wells multiplied by our working interest percentage. For the wells that produce both oil and gas, the well is typically classified as an oil or natural gas well based on the ratio of oil to natural gas production.

Oil and Gas Acreage

The following table sets forth our acreage position at December 31, 2014:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Gulf Coast region	232,129	200,851	298,234	20,538	530,363	221,389
Rocky Mountain region	359,038	316,620	232,135	110,641	591,173	427,261
Total	591,167	517,471	530,369	131,179	1,121,536	648,650

The percentage of our net undeveloped acreage that is subject to expiration over the next three years, if not renewed, is approximately 5% in 2015, 7% in 2016 and 10% in 2017.

Productive Wells

The following table sets forth our gross and net productive oil and natural gas wells as of December 31, 2014:

	Producing Oil Wells		Producing Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Operated wells						
Gulf Coast region	1,322	1,226.3	212	195.2	1,534	1,421.5
Rocky Mountain region	1,164	1,063.9	208	119.1	1,372	1,183.0
Total	2,486	2,290.2	420	314.3	2,906	2,604.5
Non-operated wells						
Gulf Coast region	26	1.5	4	0.1	30	1.6
Rocky Mountain region	101	15.2	83	28.4	184	43.6
Total	127	16.7	87	28.5	214	45.2
Total wells						
Gulf Coast region	1,348	1,227.8	216	195.3	1,564	1,423.1
Rocky Mountain region	1,265	1,079.1	291	147.5	1,556	1,226.6
Total	2,613	2,306.9	507	342.8	3,120	2,649.7

Drilling Activity

The following table sets forth the results of our drilling activities over the last three years. As of December 31, 2014, we had 13 gross (12.6 net) wells in progress.

	Year Ended December 31,					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells (1)						
Productive (2)	—	—	—	—	1	—
Non-productive (3)	—	—	—	—	—	—
Development wells (1)						
Productive (2)	59	55.9	49	44.3	201	87.4
Non-productive (3)(4)	—	—	1	1.0	5	3.2
Total	59	55.9	50	45.3	207	90.6

(1) An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well. A development well is a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(2) A productive well is an exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

(3) A non-productive well is an exploratory or development well that is not a productive well.

(4) During 2014, 2013 and 2012, an additional 43, 43 and 56 wells, respectively, were drilled for water or CO_2 injection purposes.

The following table summarizes sales volumes, sales prices and production cost information for our net oil and natural gas production for the years ended December 31, 2014, 2013 and 2012:

	Year Ended December 31,		
	2014	2013	2012
Net sales volume			
Gulf Coast region			
Oil (MBbls)	17,259	16,858	15,621
Natural gas (MMcf)	4,855	5,620	5,907
Total Gulf Coast region (MBOE)	18,068	17,795	16,606
Rocky Mountain region			
Oil (MBbls)	8,513	7,336	8,841
Natural gas (MMcf)	3,524	3,046	4,747
Total Rocky Mountain region (MBOE)	9,100	7,844	9,632
Total Company (MBOE)	27,168	25,639	26,238
Average sales prices – excluding impact of derivative settlements			
Gulf Coast region			
Oil (per Bbl)	$ 94.67	$105.34	$105.59
Natural gas (per Mcf)	4.31	3.74	2.79
Rocky Mountain region			
Oil (per Bbl)	$ 82.75	$ 89.95	$ 82.33
Natural gas (per Mcf)	3.73	3.15	3.38
Total Company			
Oil (per Bbl)	$ 90.74	$100.67	$ 97.18
Natural gas (per Mcf)	4.07	3.53	3.05
Average production cost (per BOE sold) (1)			
Gulf Coast region (2)	$ 24.92	$ 32.34	$ 24.96
Rocky Mountain region (3)	21.69	19.78	12.23
Total Company (2)	23.84	28.50	20.29

(1) Excludes oil and natural gas ad valorem and production taxes.

(2) Production costs include a net reduction of $7.1 million of lease operating expenses recorded in 2014 related to Delhi Field remediation costs and insurance reimbursements, compared to $114.0 million of lease operating expenses recorded during 2013. Excluding estimated Delhi Field remediation costs and insurance reimbursements, average production costs per BOE for the Gulf Coast region would have totaled $25.31 and $25.93 for the years ended December 31, 2014 and 2013, respectively, and average production costs per BOE for the Company as a whole would have totaled $24.10 and $24.05 for the years ended December 31, 2014 and 2013, respectively.

(3) Average production cost for the Rocky Mountain region in 2012 included operating costs related to our Bakken area assets, which generally had lower operating costs than our other properties. These assets were sold in connection with the Bakken Exchange Transaction in late 2012.

PRODUCTION AND UNIT PRICES

Further information regarding average production rates, unit sale prices and unit costs per BOE are set forth under Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Operating Results Table,* included herein.

TITLE TO PROPERTIES

As is customary in the oil and natural gas industry, Denbury conducts a limited title examination at the time of its acquisition of properties or leasehold interests targeted for enhanced recovery, and curative work is performed with respect to significant defects on higher-value properties of the greatest significance. We believe that title to our oil and natural gas properties is good and defensible, subject only to such exceptions that we believe do not materially interfere with the use of such properties, including encumbrances, easements, restrictions and royalty, overriding royalty and other similar interests.

SIGNIFICANT OIL AND GAS PURCHASERS AND PRODUCT MARKETING

Oil and natural gas sales are made on a day-to-day basis or under short-term contracts at the current area market price. We would not expect the loss of any single purchaser to have a material adverse effect upon our operations; however, the loss of a large single purchaser could potentially reduce the competition for our oil and natural gas production, which in turn could negatively impact the prices we receive. For the year ended December 31, 2014, three purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company (31%), Plains Marketing LP (13%), and ConocoPhillips (12%). For the year ended December 31, 2013, three purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company (33%), Plains Marketing LP (15%), and Eighty-Eight Oil LLC (10%). For the year ended December 31, 2012, two purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company (39%) and Plains Marketing LP (17%).

Our ability to market oil and natural gas depends on many factors beyond our control, including the extent of domestic production and imports of oil and gas, the proximity of our oil and natural gas production to pipelines, the available capacity in such pipelines, the demand for oil and natural gas, the effects of weather, and the effects of state and federal regulation. Our production in the Gulf Coast region is primarily from developed fields close to major pipelines or refineries and established infrastructure. Our production in the Rocky Mountain region is dependent on, among other factors, limited transportation options caused by oversubscribed pipelines and market centers that are distant from producing properties. As of December 31, 2014, we have not experienced significant difficulty in finding a market for all of our production as it becomes available or in transporting our production to those markets; however, there is no assurance that we will always be able to market all of our production or obtain favorable prices.

Oil Marketing

During 2012 and 2013, the oil produced in the Gulf Coast region benefited from strong pricing differentials in relation to NYMEX, and where possible we attached our production to Light Louisiana Sweet ("LLS") pricing. Overall, during 2014, we sold approximately 43% of our crude oil at prices based on the LLS index price, approximately 23% at prices partially tied to the LLS index price, and the balance at prices based on various other indexes tied to NYMEX prices, primarily in the Rocky Mountain region. During 2014, LLS pricing and NYMEX pricing have been much closer together, with the fourth quarter of 2014 quarterly average LLS-to-NYMEX differential (on a trade-month basis) narrowing to a positive $3.16 per Bbl, suggesting a potential return to long-term historical spreads compared to the wider-than-normal positive LLS-to-NYMEX spreads we experienced during 2012 and 2013. During 2014, our light sweet crude oil production in the Gulf Coast region, on average, sold for $1.80 per Bbl over NYMEX compared to $7.44 per Bbl over NYMEX in 2013 and more than $11.50 per Bbl over NYMEX in 2012. The pricing of other Gulf Coast grades of oil deteriorated somewhat during 2014, with our light and medium sour crude production selling at a discount to NYMEX of $2.43 per Bbl. The market dynamics of the region suggest that differentials to NYMEX are not expected to return to the more favorable levels seen over the last few years due to current global supply and demand indicators, as well as the influx of light sweet crude and condensate from producing regions outside of the Gulf Coast region by rail and recently completed major pipeline projects. Our current markets at various sales points along the Gulf Coast have sufficient demand to accommodate our production, but there can be no assurance of future demand. We are, therefore, monitoring the marketplace for opportunities to strategically enter into long-term marketing arrangements.

The marketing of our Rocky Mountain region oil production is dependent on transportation through local pipelines to market centers in Guernsey, Wyoming; Clearbrook, Minnesota; Wood River, Illinois; and most recently Cushing, Oklahoma. Shipments on some of the pipelines are oversubscribed and subject to apportionment. We currently have access to, or have contracted for, sufficient pipeline capacity to move our oil production; however, there can be no assurance that we will be allocated sufficient pipeline capacity to move all of our oil production in the future. Expansion of pipeline and newly built rail infrastructure in the Rocky Mountain region is ongoing and, we believe, has improved the overall stability of oil differentials in the area. However, because local demand for production is small in comparison to current production levels, much of the production in the Rocky Mountain region is transported to markets outside of the region. Therefore, prices in the Rocky Mountain region are further influenced by fluctuations in prices (primarily Brent and LLS) in coastal markets and by available pipeline capacity in the Midwest and Cushing markets. For the year ended December 31, 2014, the discount for our oil production in the Rocky Mountain region averaged $10.19 per Bbl, compared to $8.10 per Bbl during 2013 and $11.86 per Bbl during 2012. Excluding the Bakken area assets that we sold during the fourth quarter of 2012, our oil production in the Rocky Mountain region sold at a discount to NYMEX of $8.43 per Bbl during the year ended December 31, 2012.

Natural Gas Marketing

Virtually all of our natural gas production in the Gulf Coast region is close to existing pipelines; consequently, we generally have a variety of options to market our natural gas. However, our natural gas production in the Rocky Mountain region, like our oil production, is dependent on, among other factors, limited transportation options that can affect our ability to find markets for it. We sell the majority of our natural gas on one-year contracts, with prices fluctuating month to month based on published pipeline indices and with slight premiums or discounts to the index. We currently receive near NYMEX or Henry Hub prices for most of our natural gas sales in Mississippi. For the year ended December 31, 2014, the amount received for our Mississippi natural gas production averaged $0.25 per Mcf over NYMEX prices. In the Texas Gulf Coast region, due primarily to its location, the price we received for the year ended December 31, 2014, averaged $0.21 per Mcf below NYMEX prices. The CCA natural gas production in the Rocky Mountain region is sold at the wellhead on a percent-of-proceeds basis. We receive a percentage of proceeds on both the residue natural gas volumes and the natural gas liquids volumes. The natural gas has a significant component of propane, butanes and other higher-density hydrocarbons, resulting in a measurable natural gas liquids stream. In addition, we have coal bed methane production in the Hartzog Draw that is sold at the Cheyenne Hub. For the year ended December 31, 2014, we averaged $0.53 per Mcf below NYMEX prices for our Rocky Mountain region natural gas production due primarily to its location, the natural gas liquids extracted from the CCA gas stream (resulting in a decreased net price), and the quality of the coal bed methane gas in Wyoming.

COMPETITION AND MARKETS

We face competition from other oil and natural gas companies in all aspects of our business, including acquisition of producing properties, oil and gas leases, drilling rights, and CO_2 properties; marketing of oil and natural gas; and obtaining and maintaining goods, services and labor. Many of our competitors have substantially larger financial and other resources. Factors that affect our ability to acquire producing properties include available liquidity, available information about prospective properties and our expectations for earning a minimum projected return on our investments. Because of the primary nature of our core assets (our tertiary operations) and our ownership of relatively uncommon significant natural sources of CO_2 in the Gulf Coast and Rocky Mountain regions, we believe that we are effective in competing in the market and have less competition than our peers in certain aspects of our business.

The demand for qualified and experienced field personnel to drill wells and conduct field operations and for geologists, geophysicists, engineers and other professionals in the oil and gas industry can fluctuate significantly, often in correlation with commodity prices, causing periodic shortages in such personnel. In recent years, the competition for qualified technical personnel has been extensive, and our personnel costs have been escalating. There have also been periods with shortages of drilling rigs and other equipment, as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. We cannot be certain when we will experience these issues, and these types of shortages or price increases could significantly decrease our profit margin, cash flow and operating results, and cause significant delays in our development operations.

FEDERAL AND STATE REGULATIONS

Numerous federal, state and local laws and regulations govern the oil and gas industry. Additions or changes to these laws and regulations are often made in response to the current political or economic environment. Compliance with the evolving regulatory landscape is often difficult, and substantial penalties may be incurred for noncompliance. Additionally, the future annual cost of complying with all laws and regulations applicable to our operations is uncertain and will be ultimately determined by several factors, including future changes to legal and regulatory requirements. Management believes that continued compliance with existing laws and regulations applicable to our operations and future compliance therewith will not have a materially adverse effect on our consolidated financial position, results of operations or cash flows, although such laws and regulations, and compliance therewith, could cause significant delays or otherwise impede operations, which may, among other things, cause our expected production rates and cash flows to be less than anticipated.

The following sections describe some specific laws and regulations that may affect us. We cannot predict the cost or impact of these or other future legislative or regulatory initiatives.

Regulation of Natural Gas and Oil Exploration and Production

Our operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for drilling wells; maintaining bonding requirements in order to drill or operate wells and regulating the location of wells; the method of drilling and casing wells; the surface use and restoration of properties upon which wells are drilled; the plugging and abandoning of wells; and the composition or disposal of chemicals and fluids used in connection with operations. Our operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling, spacing or proration units and the density of wells that may be drilled in those units, and the unitization or pooling of oil and gas properties. In addition, state conservation laws, which establish maximum rates of production from oil and gas wells, generally prohibit or restrict the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these laws and regulations may limit the amount of oil and natural gas we can produce from our wells and may limit the number of wells or the locations at which we can drill. Regulatory requirements and compliance relative to the oil and gas industry increase our costs of doing business and, consequently, affect our profitability.

Federal Regulation of Sales Prices and Transportation

The transportation of, and certain sales with respect to, natural gas in interstate commerce are heavily regulated by agencies of the U.S. federal government and are affected by, among other things, the availability, terms and cost of transportation. Notably, the price and terms of access to pipeline transportation are subject to extensive U.S. federal and state regulation. The Federal Energy Regulatory Commission ("FERC") is continually proposing and implementing new and/or modified rules and regulations affecting the natural gas industry, some of which may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. While our sales of crude oil, condensate and natural gas liquids are not currently subject to FERC regulation, our ability to transport and sell such products is dependent on certain pipelines whose rates, terms and conditions of service are subject to FERC regulation. Additional proposals and proceedings that might affect the natural gas industry are considered from time to time by Congress, FERC, state regulatory bodies and the courts, and we cannot predict when or if any such proposals or proceedings might become effective and their effect or impact, if any, on our operations.

Federal Energy and Climate Change Legislation and Regulation

In early 2012, the President signed the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011. This act, among other things, updates federal pipeline safety standards, increases penalties for violations of such standards, gives the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (the "PHMSA") authority for new damage prevention and incident notification, and directs the PHMSA to prescribe new minimum safety standards for CO_2 pipelines, which safety standards could affect our operations and the costs thereof. While the PHMSA has adopted or proposed to adopt a number of new regulations to implement this act, no new minimum safety standards have been proposed or adopted for CO_2 pipelines. In the future, Congress may create new incentives for alternative energy sources and may also consider legislation to reduce emissions of CO_2 or other greenhouse gases. This legislation, if enacted, could (1) impose a tax or other economic penalty on the production of fossil fuels that, when used, ultimately release CO_2, (2) reduce the demand for, and uses of, oil, gas and other minerals, and/or (3) increase the costs incurred by us in our exploration and production activities. The Environmental Protection Agency ("EPA") has promulgated regulations requiring permitting for certain sources of greenhouse gas emissions, and has announced its intention to assess methane and other greenhouse gas emissions from the oil and gas sector and to adopt amended regulations if further reductions are warranted. At the same time, legislation or regulation to reduce the emissions of CO_2 or other greenhouse gases could also create economic incentives for technologies and practices that reduce or avoid such emissions, including processes that recognize the associated storage of CO_2 in oil and gas reservoirs through CO_2 EOR operations.

Natural Gas Gathering Regulations

State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory-take requirements. With the increase in construction and operation of natural gas gathering lines in various states, natural gas gathering is receiving greater regulatory scrutiny from state regulatory agencies, which is likely to continue in the future.

Federal, State or Indian Leases

Our operations on federal, state or Indian oil and gas leases, especially those in the Rocky Mountain region, are subject to numerous restrictions, including nondiscrimination statutes. Such operations must be conducted pursuant to certain on-site security regulations and other permits and authorizations issued by the Bureau of Land Management, the Bureau of Ocean Energy Management, the Bureau of Safety and Environmental Enforcement, the Bureau of Indian Affairs, and other federal and state stakeholder agencies.

Environmental Regulations

Our oil and natural gas production, saltwater disposal operations, injection of CO_2, and the processing, handling and disposal of materials such as hydrocarbons and naturally occurring radioactive materials ("NORM") are subject to stringent regulation. We could incur significant costs, including cleanup costs resulting from a release of product, third-party claims for property damage and personal injuries, or penalties and other sanctions as a result of any violations or liabilities under environmental or other laws applicable to our operations. Changes in, or more stringent enforcement of, environmental laws and other laws applicable to our operations could also result in delays or additional operating costs and capital expenditures.

Various federal, state and local laws and regulations controlling the discharge of materials into the environment, or otherwise relating to the protection of the environment, directly impact our oil and gas exploration, development and production operations. These include, among others, (1) regulations adopted by the EPA and various state agencies regarding approved methods of disposal for certain hazardous and nonhazardous wastes; (2) the Comprehensive Environmental Response, Compensation, and Liability Act and analogous state laws that regulate the removal or remediation of previously disposed wastes (including wastes disposed of or released by prior owners or operators), property contamination (including groundwater contamination), and remedial plugging operations to prevent future contamination; (3) the Clean Air Act and comparable state and local requirements already applicable to our operations and new restrictions on air emissions from our operations, including greenhouse gas emissions and those that could discourage the production of fossil fuels that, when used, ultimately release CO_2; (4) the Oil Pollution Act of 1990, which contains numerous requirements relating to the prevention of, and response to, oil spills into waters of the United States; (5) the Resource Conservation and Recovery Act, which is the principal federal statute governing the treatment, storage and disposal of hazardous wastes; (6) the Endangered Species Act and counterpart state legislation, which protects certain species (and their related habitats), including certain species that could be present on our leases, as threatened or endangered; and (7) state regulations and statutes governing the handling, treatment, storage and disposal of NORM.

Management believes that we are currently in substantial compliance with existing applicable environmental laws and regulations, and does not currently anticipate that future compliance will have a materially adverse effect on our consolidated financial position, results of operations or cash flows, although such laws and regulations, and compliance therewith, could cause significant delays or otherwise impede operations, which may, among other things, cause our expected production rates and cash flows to be less than anticipated.

Hydraulic Fracturing

During 2014, we fracture stimulated five operated wells at Hartzog Draw Field utilizing water-based fluids with no diesel fuel component. We currently have no plans to hydraulically fracture additional wells at Hartzog Draw Field during 2015. However, we are familiar with the laws and regulations applicable to hydraulic fracturing operations and take steps to ensure compliance with these requirements.

ESTIMATED NET QUANTITIES OF PROVED OIL AND NATURAL GAS RESERVES AND PRESENT VALUE OF ESTIMATED FUTURE NET REVENUES

Internal Controls Over Reserve Estimates

Reserve information in this report is based on estimates prepared by D&M, an independent petroleum engineering consulting firm located in Dallas, Texas, utilizing data provided by our internal reservoir engineering team and is the responsibility of management. We rely on D&M's expertise to ensure that our reserve estimates are prepared in compliance with SEC rules and regulations and that appropriate geologic, petroleum engineering, and evaluation principles and techniques are applied in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)". The person responsible for the preparation of the reserve report is a Senior Vice President at D&M; he is a Registered Professional Engineer in the State of Texas. He received a Bachelor of Science degree in Petroleum Engineering at Texas A&M University in 1974, and he has in excess of 40 years of experience in oil and gas reservoir studies and evaluations. Our Senior Vice President – Development, Technical and Innovation is primarily responsible for overseeing the independent petroleum engineering firm during the process. Our Senior Vice President – Development, Technical and Innovation has a Master of Science and Bachelor of Science degree in Chemical Engineering from Columbia University, a Bachelor of Science in Chemistry from Davidson College and over 31 years of industry experience working with petroleum reserve estimates. D&M relies on various data provided by our internal reservoir engineering team in preparing its reserve estimates, including such items as oil and natural gas prices, ownership interests, production information, operating costs, planned capital expenditures and other technical data. Our internal reservoir engineering team consists of qualified petroleum engineers who maintain the Company's internal evaluation of reserves and compare the Company's information to the reserves prepared by D&M. Management is responsible for designing the internal control procedures used in the preparation of our oil and gas reserves, which include verification of data input into reserve forecasting and economics evaluation software, as well as multi-discipline management reviews. The internal reservoir engineering team reports directly to our Senior Vice President – Development, Technical and Innovation. In addition, our Board of Directors' Reserves and Health, Safety and Environmental ("HSE") Committee, on behalf of the Board of Directors, oversees the qualifications, independence, performance and hiring of our independent petroleum engineering firm and reviews the final report and subsequent reporting of our oil and natural gas reserve estimates. The Chairman of the Reserves and HSE Committee holds a Ph.D. in Chemical Engineering from the Massachusetts Institute of Technology and bachelor's degrees in Chemistry and Mathematics from Capital University in Ohio. He has 35 years of industry experience, with responsibilities including reserves preparation and approval.

Oil and Natural Gas Reserve Estimates

D&M prepared estimates of our net proved oil and natural gas reserves as of December 31, 2014, 2013 and 2012. See the summary of D&M's report as of December 31, 2014, included as an exhibit to this Form 10-K. These estimates of reserves were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices on the first day of each month within the 12-month period in accordance with rules and regulations of the SEC. These oil and natural gas reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties. During 2014, we provided oil and gas reserve estimates for 2013 to the United States Energy Information Agency that were substantially the same as the reserve estimates included in our Form 10-K for the year ended December 31, 2013.

Our proved non-producing reserves primarily relate to reserves that are to be recovered from productive zones that are currently behind pipe. Since a majority of our properties are in areas with multiple pay zones, these properties may have both proved producing and proved non-producing reserves.

As of December 31, 2014, our estimated proved undeveloped reserves totaled approximately 99.0 MMBOE, or approximately 23% of our estimated total proved reserves, a decline of 81.0 MMBOE from December 31, 2013 levels for these reserves. Our proved undeveloped oil reserves primarily relate to our CO_2 tertiary operations (80.5 MMBOE), and our proved undeveloped natural gas reserves are primarily located in our Riley Ridge Field (5.9 MMBOE). We generally consider the CO_2 tertiary proved undeveloped reserves to be lower risk than other proved undeveloped reserves that require drilling at locations offsetting existing production, because all of these proved undeveloped reserves are associated with tertiary recovery operations in fields and reservoirs that historically produced substantial volumes of oil under primary production.

During 2014, we spent approximately $130 million to convert 79.9 MMBOE of proved undeveloped reserves to proved developed reserves, primarily related to behind-pipe reserves at Riley Ridge, as well as continued tertiary development activities at Heidelberg, Tinsley, Bell Creek, and Oyster Bayou fields. During 2014, we added 4.3 MMBOE of proved undeveloped reserves primarily related to our non-tertiary operations at CCA, and recognized other net downward proved undeveloped reserve revisions of 5.4 MMBOE.

As of December 31, 2014, 42.0 MMBOE of our total proved undeveloped reserves are not scheduled to be developed within five years of initial booking, nearly all of which are part of CO_2 EOR projects. We believe these reserves satisfy the conditions to be included as proved reserves because (1) we have established and continue to follow the previously adopted development plan for each of these projects; (2) we have significant ongoing development activities in each of these CO_2 EOR projects and (3) we have a historical record of completing the development of comparable long-term projects.

The following table provides certain estimated proved reserve information in total and by category, as well as related pricing information as of December 31, 2014, 2013 and 2012. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and their values, including many factors beyond our control. See Item 1A, *Risk Factors – Estimating our reserves, production and future net cash flows is difficult to do with any certainty.* See also *Supplemental Oil and Natural Gas Disclosures (Unaudited)* to the Consolidated Financial Statements for further discussion of reserve inputs and changes between periods.

	December 31, 2014	December 31, 2013	December 31, 2012
Estimated proved reserves (1)			
Oil (MBbls)	362,335	386,659	329,124
Natural gas (MMcf)	452,402	489,954	481,641
Oil equivalent (MBOE)	437,735	468,318	409,398
Reserve volumes categories			
Proved developed producing			
Oil (MBbls)	240,004	245,722	208,745
Natural gas (MMcf)	72,799	68,976	60,832
Oil equivalent (MBOE)	252,137	257,218	218,884
Proved developed non-producing			
Oil (MBbls)	29,373	30,670	27,264
Natural gas (MMcf) (2)	343,622	3,119	3,359
Oil equivalent (MBOE)	86,643	31,190	27,824
Proved undeveloped			
Oil (MBbls)	92,958	110,267	93,115
Natural gas (MMcf) (2)	35,981	417,859	417,450
Oil equivalent (MBOE)	98,955	179,910	162,690
Percentage of total MBOE			
Proved developed producing	57%	55%	53%
Proved developed non-producing	20%	7%	7%
Proved undeveloped	23%	38%	40%
Representative oil and natural gas prices (3)			
Oil – NYMEX	$ 94.99	$ 96.94	$ 94.71
Natural gas – Henry Hub	4.30	3.67	2.85
Present values (in thousands) (4)			
Discounted estimated future net cash flows before income taxes (PV-10 Value) (5)	$8,748,069	$10,633,783	$9,909,592
Standardized measure of discounted estimated future net cash flows after income taxes ("Standardized Measure")	$5,908,128	$ 7,128,744	$6,414,380

(1) Estimated proved reserves as of December 31, 2012, reflect the sale of reserves associated with our Bakken area assets sold in 2012 (approximately 109 MMBOE), but do not include reserves of 42.2 MMBOE related to the CCA Acquisition, acquired during the first quarter of 2013.

(2) In 2014, we converted approximately 364 Bcf of proved undeveloped natural gas reserves at Riley Ridge to proved developed non-producing reserves, as these reserves are behind pipe during the period in which the Riley Ridge gas processing facility is shut-in, which we currently expect will continue until 2016.

(3) The reference prices were based on the arithmetic average of the first-day-of-the-month NYMEX commodity prices for each month during the respective year. These prices do not reflect adjustments for market differentials by field that are utilized in the preparation of our reserve report to arrive at the appropriate net price we receive, and also do not reflect significant crude oil price declines in late 2014 and early 2015, when oil prices dropped rapidly, declining to below $45 per Bbl in January 2015. In response to these price decreases, we have deferred our development spending for certain projects in 2015, which has been reflected in our December 31, 2014, reserve report. Sustained prices at these recent levels would result in a significant decrease in our proved reserve value, and to a lesser degree, a reduction in our proved reserve volumes. See *Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Operating Results Table* for details of oil and natural gas prices received, both including and excluding the impact of derivative settlements.

(4) Determined based on the average first-day-of-the-month prices for each month, adjusted to prices received by field in accordance with standards set forth in the FASC. The decrease in the PV-10 Value and the Standardized Measure in 2014 was significantly impacted by the decline in oil prices we received relative to NYMEX oil prices (our NYMEX oil price differential) between 2013 and 2014. The weighted-average oil price differentials utilized were $3.10 per Bbl below representative NYMEX oil prices as of December 31, 2014, compared to $3.41 per Bbl and $7.57 per Bbl above representative NYMEX oil prices as of December 31, 2013 and 2012, respectively.

(5) PV-10 Value is a non-GAAP measure and is different from the Standardized Measure in that PV-10 Value is a pre-tax number and the Standardized Measure is an after-tax number. The information used to calculate PV-10 Value is derived directly from data determined in accordance with FASC Topic 932. The difference between these two amounts, the discounted estimated future income tax, was $2.84 billion at December 31, 2014; $3.51 billion at December 31, 2013; and $3.50 billion at December 31, 2012. We believe that PV-10 Value is a useful supplemental disclosure to the Standardized Measure because the Standardized Measure can be impacted by a company's unique tax situation, and it is not practical to calculate the Standardized Measure on a property-by-property basis. Because of this, PV-10 Value is a widely used measure within the industry and is commonly used by securities analysts, banks and credit rating agencies to evaluate the estimated future net cash flows from proved reserves on a comparative basis across companies or specific properties. PV-10 Value is commonly used by us and others in our industry to evaluate properties that are bought and sold and to assess the potential return on investment in our oil and gas properties. PV-10 Value is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for the Standardized Measure. Our PV-10 Value and the Standardized Measure do not purport to represent the fair value of our oil and natural gas reserves. See *Glossary and Selected Abbreviations* for the definition of "PV-10 Value" and see *Supplemental Oil and Natural Gas Disclosures (Unaudited)* to the Consolidated Financial Statements for additional disclosures about the Standardized Measure.

Item 1A. Risk Factors

A lengthy period of low oil prices or their further deterioration could adversely affect our future financial condition, results of operations, cash flows, the carrying value of our oil and gas properties, our dividend payments and our growth prospects.

As discussed in greater detail in the risk factors below, NYMEX oil prices have declined from $107 per Bbl in June 2014 to below $45 per Bbl in January 2015. If oil prices remain at late 2014 or early 2015 levels or decline further for an extended period of time, we could be harmed in a number of ways:

- lower cash flows from operations may require continued or further reduced levels of capital expenditures;
- reduced levels of capital expenditures in turn could lower our present and future production levels, and lower the quantities and value of our oil and gas reserves, which constitute our major asset;
- our lenders could reduce our borrowing base, and we may not be able to raise capital at attractive rates in the public markets;
- cause us to change our policy of paying regular cash dividends, or reduce the amount of dividends below the current rate;
- we could be required to impair various assets, including a write-down of our oil and gas assets, our goodwill or the value of other tangible or intangible assets;
- construction of plants that produce CO_2 as a byproduct that we can purchase could be delayed or cancelled, thus limiting the amount of industrial-source CO_2 available for use in our tertiary operations; and/or
- our potential cash flows from our 2015 and 2016 commodity derivative contracts that include sold puts could be limited to the extent that oil prices are below the prices of those sold puts.

If oil prices fall to lower levels, some or all of our tertiary projects could become uneconomical. We may decide to suspend future expansion projects, and if prices were to drop below our cash break-even point for an extended period of time, we may further decide to shut-in existing production, both of which could have a material adverse effect on our operations and reduce our production. Since operating costs do not decrease as quickly as commodity prices, it is difficult to determine a current precise break-even point for our tertiary projects; however, based on prior history, we currently estimate an industry-competitive rate of return at relatively low oil prices, depending on the specific field and area.

Oil and natural gas prices are volatile.

Oil and natural gas prices historically have been volatile and may continue to be volatile in the future. Therefore, even if oil prices recover for a period of time, volatility will remain, and prices could move downward or upward on a rapid or repeated basis, which can make transactions, valuations and business strategies difficult. Our cash flow from operations is highly dependent on the prices that we receive for oil. Oil prices currently affect us more than natural gas prices because oil comprised approximately 95% of our 2014 production and 83% of our proved reserves at December 31, 2014. The prices for oil and natural gas are subject to a variety of factors that are beyond our control. These factors include the supply of, and demand for, these commodities, which fluctuate with changes in market and economic conditions and other factors, including:

- the level of worldwide consumer demand for oil and natural gas and the domestic and foreign supply of oil and natural gas and levels of domestic oil and gas storage;
- the degree to which members of the Organization of Petroleum Exporting Countries maintain oil price and production controls;
- the degree to which domestic oil and natural gas production decreases U.S. imports of crude oil;
- domestic governmental regulations and taxes;
- adverse weather conditions, including hurricanes and tropical storms in and around the Gulf of Mexico that can damage oil and natural gas facilities and delivery systems and disrupt operations, and winter conditions and forest fires in the Rocky Mountains that can delay or impede operations;
- commodity and financial market uncertainty;
- worldwide political events and conditions, including actions taken by foreign oil and natural gas producing nations; and
- worldwide economic conditions.

These factors and the volatility of the energy markets generally make it extremely difficult to predict future oil and natural gas price movements. For the past several years, we have employed a strategy of hedging a substantial portion of our forecasted production approximately 18 months to two years into the future (from the then-current quarter), to mitigate the risks associated with price fluctuations (see Note 9, *Commodity Derivative Contracts,* to the Consolidated Financial Statements for details regarding our commodity derivative contracts). As of February 19, 2015, we have oil derivative contracts in place covering 58,000 Bbls/d for the first three quarters of 2015, 38,000 Bbls/d for the fourth quarter of 2015, 36,000 Bbls/d for the first quarter of 2016, and 12,000 Bbls/d for the second quarter of 2016. With the decline in commodity futures prices in late 2014 and early 2015, as of late February 2015, we have deferred entering into new oil derivative contracts since the third quarter of 2014. Therefore, as of late February 2015, the percentage of our forecasted oil production that is currently hedged for the fourth quarter of 2015 and calendar 2016 is less than the percentage hedged in recent years. During periods of lower oil prices, we may defer entering into new contracts until futures prices return to levels that we consider economically conducive to our doing so.

The prices we receive for our crude oil often do not correlate with NYMEX prices and can vary from such prices depending on, among other factors, the quality of the crude oil we sell, the location of our crude oil production and the related markets to which we sell, variations in prices paid based upon different indices used, and the pricing contracts and indices at which we sell production. Our NYMEX differentials on a field-by-field basis over the last few years have ranged from approximately $23 per Bbl above NYMEX to approximately $25 per Bbl below NYMEX. On a corporate-wide basis, our NYMEX differentials over the last few years have ranged from approximately $11 per Bbl above NYMEX oil prices to approximately $5 per Bbl below NYMEX oil prices. These variances have been due to various factors and are difficult to forecast or anticipate, but they have a direct impact on the net oil price we receive. In recent years we have benefited from the favorable differential for sales based upon the LLS index relative to NYMEX prices, but market dynamics of the region over the past year suggest that these differentials to NYMEX are unlikely to return to the more favorable levels seen previously due to the influx of light sweet crude and condensate from producing regions outside of the Gulf Coast region. See *Significant Oil and Gas Purchasers and Product Marketing* and *Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Oil and Natural Gas Revenues* for further discussion.

A financial downturn in one or more of the world's major markets could negatively affect our liquidity, business and financial condition.

Liquidity is essential to our business. Our liquidity could be substantially negatively affected by an inability to obtain capital in the long-term or short-term debt capital markets or equity capital markets or an inability to access bank financing. A prolonged credit crisis, including a severe economic contraction in Europe or turmoil in the global financial system, could materially affect our liquidity, business and financial condition. In the past, such conditions have adversely impacted financial markets and have created substantial volatility and uncertainty with the related negative impact on global economic activity. Negative credit market conditions could inhibit our lenders from fully funding our bank credit facility or cause them to make the terms of our bank credit facility more costly and more restrictive. Negative economic conditions could also adversely affect the collectability of our trade receivables or performance by our suppliers or cause our commodity hedging arrangements to be ineffective if our counterparties are unable to perform their obligations or otherwise seek bankruptcy protection.

Our production will decline if our access to sufficient amounts of carbon dioxide is limited.

Our long-term strategy is primarily focused on our CO_2 tertiary recovery operations. The crude oil production from our tertiary recovery projects depends, in large part, on having access to sufficient amounts of CO_2. Our ability to produce oil from these projects would be hindered if our supply of CO_2 was limited due to, among other things, problems with our current CO_2 producing wells and facilities, including compression equipment, or catastrophic pipeline failure. This could have a material adverse effect on our financial condition, results of operations and cash flows. Our anticipated future crude oil production from tertiary operations is also dependent on the timing, volumes and location of CO_2 injections and, in particular, on our ability to increase our combined purchased and produced volumes of CO_2 and inject adequate amounts of CO_2 into the proper formation and area within each of our tertiary oil fields.

The development of our principal CO_2 source at Jackson Dome involves the drilling of wells to increase and extend the CO_2 reserves available for use in our tertiary fields. These drilling activities are subject to many of the same drilling and geological risks of drilling and producing oil and gas wells (see *Oil and natural gas development and producing operations involve various risks* below). Recent market conditions may well cause the delay or cancellation of construction of plants that produce CO_2 as a byproduct that we can purchase, thus limiting the amount of industrial-source CO_2 available for our use in our tertiary operations.

Our level of indebtedness may adversely affect operations and limit our growth.

As of December 31, 2014, our outstanding senior indebtedness consisted of $2.9 billion principal amount of subordinated notes, virtually all of which have maturity dates between 2021 and 2023 at interest rates ranging from 4.625% to 6.375% per annum at a weighted average interest rate of 5.26% per annum, and $395.0 million principal amount outstanding under our bank credit facility. We currently have a borrowing base of $3.0 billion and total lender commitments of $1.6 billion under our bank credit facility and, at December 31, 2014, availability with respect to such commitments of $1.2 billion. Our bank borrowing base is adjusted annually and upon requested unscheduled special redeterminations, in each case at the banks' discretion, and the amount is established and based, in part, upon certain external factors, such as commodity prices. We do not know, nor can we control, the results of such redeterminations or the effect of then-current oil and natural gas prices on any such redetermination. A future redetermination lowering our borrowing base could limit availability under our bank credit facility. If the outstanding debt under our bank credit facility exceeds the then-effective and redetermined borrowing base, we will be required to repay the excess amount over a period not to exceed six months.

The level of our indebtedness could have important consequences, including but not limited to the following:

- impairing our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions or general corporate and other purposes;
- potentially restricting us from making acquisitions or exploiting business opportunities;
- lowering our available cash flow if market interest rates increase or if the level of our indebtedness significantly increases;
- requiring dedication of a substantial portion of our cash flows from operations to servicing our indebtedness (so that such cash flows would not be available for capital expenditures or other purposes); and
- limiting our ability to borrow additional funds, dispose of assets, pay dividends, fund share repurchases and make certain investments.

The debt covenants contained in the agreements governing our outstanding indebtedness may also affect our flexibility in reacting to changes in the economy and in our industry. For example, as our cash flow from operations is highly dependent on the prices that we receive for oil and natural gas, if oil and natural gas prices remain at depressed levels for an extended period of time, our degree of leverage could increase significantly or our leverage metrics could deteriorate, potentially causing us to not be in compliance with our bank credit facility's maximum permitted ratio of consolidated total net debt to consolidated EBITDAX (as defined in the bank credit facility) of not more than 4.25 to 1.0 (see Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Bank Credit Facility*). If we are unable to generate sufficient cash flows or otherwise obtain funds necessary to make required payments on our indebtedness, or if we otherwise fail to comply with the various covenants related to such indebtedness, including covenants in our bank credit facility, we would be in default under our debt instruments. Any such default, if not cured or waived, could permit the holders of such indebtedness to accelerate the maturity of such indebtedness and could cause defaults under other indebtedness, which could have a material adverse effect on us. Our ability to meet our obligations under our debt instruments will depend, in part, upon our future performance, which will be subject to prevailing economic conditions, commodity prices, and financial, business and other factors, including factors beyond our control.

Our planned tertiary operations and the related construction of necessary CO_2 pipelines could be delayed by difficulties in obtaining pipeline rights-of-way and/or permits, and/or by the listing of certain species as threatened or endangered.

The production of crude oil from our planned tertiary operations is dependent upon having access to pipelines to transport available CO_2 to our oil fields at a cost that is economically viable. Our current and future construction of CO_2 pipelines will require us to obtain rights-of-way from private landowners and from the federal government in certain areas. Certain states where we operate have considered or may again consider the adoption of laws or regulations that could limit or eliminate the ability of a state, state's legislature or its administrative agencies to exercise eminent domain over private property, in addition to possible judicially imposed constraints on, and additional requirements for, the exercise of eminent domain. We also conduct operations on federal and other oil and natural gas leases inhabited by species, such as the sage grouse, that could be listed as threatened or endangered under the Endangered Species Act, which listing could lead to tighter restrictions as to federal land use. These laws and regulations, together with any other changes in law related to the use of eminent domain or the listing of certain species as threatened or endangered, could inhibit or eliminate our ability to secure rights-of-way or otherwise access land for current or future pipeline construction projects. As a result, obtaining rights-of-way or other means of access may require additional regulatory and environmental compliance, and increased costs in connection therewith, which could delay our CO_2 pipeline construction schedule and initiation of our pipeline operations, and/or increase the costs of constructing our pipelines.

Oil and natural gas development and producing operations involve various risks.

Our operations are subject to all the risks normally incident and inherent to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including, without limitation, well blowouts; cratering and explosions; pipe failure; fires; formations with abnormal pressures; uncontrollable flows of oil, natural gas, brine or well fluids; release of contaminants into the environment and other environmental hazards and risks. In addition, our operations are sometimes near populated commercial or residential areas, which add additional risks. The nature of these risks is such that some liabilities could exceed our insurance policy limits or otherwise be excluded from, or limited by, our insurance coverage, as in the case of environmental fines and penalties, for example, which are excluded from coverage as they cannot be insured.

We could incur significant costs related to these risks that could have a material adverse effect on our results of operations, financial condition and cash flows. Our CO_2 tertiary recovery projects require a significant amount of electricity to operate the related facilities, which is our largest single cost related to the projects. If these costs or others were to increase significantly, it could have an adverse effect upon the profitability of these operations. Additionally, a portion of our production activities involves CO_2 injections into fields with wells plugged and abandoned by prior operators. Although it is often difficult (or impracticable) to determine whether a well has been properly plugged prior to commencing injections and pressuring the oil reservoirs, we have budgeted $45 million for this effort for 2015. We may incur significant costs in connection with remedial plugging operations to prevent environmental contamination and to otherwise comply with federal, state and local regulation relative to the plugging and abandoning of our oil, natural gas and CO_2 wells. In addition to the increased costs, if wells have not been properly plugged, modification to those wells may delay our operations and reduce our production.

While mitigated somewhat by our significant emphasis on tertiary recovery operations in fields and reservoirs that have historically produced substantial volumes of oil under primary production, development activities are subject to many risks, including the risk that we will not recover all or any portion of our investment in such wells. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Further, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions, including hurricanes and tropical storms in and around the Gulf of Mexico that can damage oil and natural gas facilities and delivery systems and disrupt operations, and winter conditions and forest fires in the Rocky Mountain region that can delay or impede operations;
- compliance with environmental and governmental requirements; and
- the cost of, or shortages or delays in the availability of, drilling rigs, equipment, pipelines and services.

Estimating our reserves, production and future net cash flows is difficult to do with any certainty.

Estimating quantities of proved oil and natural gas reserves is a complex process. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors such as future commodity prices, production costs, severance and excise taxes, capital expenditures and workover and remedial costs, and the assumed effect of governmental rules and regulations. There are numerous uncertainties about when a property may have proved reserves as compared to potential or probable reserves, particularly relating to our tertiary recovery operations. Forecasting the amount of oil reserves recoverable from tertiary operations, and the production rates anticipated therefrom, requires estimates, one of the most significant being the oil recovery factor. Actual results most likely will vary from our estimates. Also, the use of a 10% discount factor for reporting purposes, as prescribed by the SEC, may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our business, and the oil and natural gas industry in general, are subject. Any significant inaccuracies in these interpretations or assumptions, or changes of conditions, could result in a revision of the quantities and net present value of our reserves.

The reserves data included in documents incorporated by reference represent estimates only. Quantities of proved reserves are estimated based on economic conditions, including first-day-of-the-month average oil and natural gas prices for the 12-month period preceding the date of the assessment. The representative oil and natural gas prices used in estimating our December 31, 2014 reserves were $94.99 per Bbl for crude oil and $4.30 per MMBtu for natural gas, both of which were adjusted for market differentials by field. This prescribed methodology does not reflect significant crude oil price declines in late 2014 and early 2015, when oil prices dropped rapidly, declining to below $45 per Bbl in January 2015. In response to these price decreases, we have deferred our development spending for certain projects in 2015, which has been reflected in our December 31, 2014 reserve report. Sustained prices at late 2014 or early 2015 levels would result in a significant decrease in our proved reserve value, and to a lesser degree, a reduction in our proved reserve volumes, which may cause us to begin recording write-downs due to the full cost ceiling test in the first or second quarter of 2015, and also in subsequent quarterly periods if prices remain low. Our reserves and future cash flows may be subject to revisions based upon changes in economic conditions, including oil and natural gas prices, as well as due to production results, results of future development, operating and development costs, and other factors. Downward revisions of our reserves could have an adverse effect on our financial condition and operating results. Actual future prices and costs may be materially higher or lower than the prices and costs used in our estimates.

As of December 31, 2014, approximately 23% of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and may require successful drilling operations. The reserves data assumes that we can and will make these expenditures and conduct these operations successfully, but these assumptions may not be accurate, and these expenditures and operations may not occur.

There are no assurances of our ability to pay dividends in the future and at what level.

During 2014, we declared a regular quarterly dividend of $0.0625 per outstanding common share, and have declared a similar dividend for the first quarter of 2015. While we currently intend to continue to pay regular quarterly cash dividends, our ability to pay dividends may be adversely affected if certain of the other risks described herein were to occur. Our payment of dividends is subject to, and conditioned upon, among other things, compliance with the covenants and restrictions contained in our bank credit facility and the indentures governing our subordinated notes. All dividends will be paid at the discretion of our Board of Directors and will depend upon many factors, including oil prices and their impact on our cash flows, financial condition and such other factors as our Board of Directors may deem relevant from time to time. There are no assurances as to our ability to pay dividends in the future or the level thereof.

Our future performance and growth rate depend upon our ability to find or acquire additional oil and natural gas reserves that are economically recoverable.

Unless we can successfully replace the reserves that we produce, our reserves will decline, resulting eventually in a decrease in oil and natural gas production and lower revenues and cash flows from operations. We have historically replaced reserves through both acquisitions and internal organic growth activities. For internal organic growth activities, the magnitude of proved reserves that we can book in any given year depends on our progress with new floods and the timing of the production response; there were no significant additions to our oil and natural gas reserves in 2014, as we initiated no new floods in 2014. In the future, we may not be able to continue to replace reserves at acceptable costs. The business of exploring for, developing or acquiring reserves is capital intensive. We may not be able to make the necessary capital investment to maintain or expand our oil and natural gas reserves if our cash flows from operations are reduced, whether due to lower oil or natural gas prices or otherwise, or if external sources of capital become limited or unavailable. Further, the process of using CO_2 for tertiary recovery, and the related infrastructure, requires significant capital investment up to five years prior to any resulting and associated production and cash flows from these projects, heightening potential capital constraints. If we do not continue to make significant capital expenditures, or if outside capital resources become limited, we may not be able to maintain our growth rate or otherwise meet expectations.

During the last few years, we have acquired several fields at a substantial cost because we believe that they have significant additional production potential through tertiary flooding, and we may have the opportunity to acquire other oil fields that we believe are tertiary flood candidates, requiring significant amounts of capital. If we are unable to successfully develop and produce the potential oil in any acquired fields, it would negatively affect our return on investment relative to these acquisitions and could significantly reduce our ability to obtain additional capital for the future or fund future acquisitions, and also negatively affect our financial results to a significant degree.

Commodity derivative contracts may expose us to potential financial loss.

To reduce our exposure to fluctuations in the prices of oil and natural gas, we enter into commodity derivative contracts in order to economically hedge a substantial portion of our forecasted oil and natural gas production. Derivative contracts expose us to risk of financial loss in some circumstances, including when there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received, when the cash benefit from hedges including a sold put is limited to the extent oil prices fall below the price of our sold puts, or when the counterparty to the derivative contract is financially constrained and defaults on its contractual obligations. In addition, these derivative contracts may limit the benefit we would otherwise receive from increases in the prices for oil and natural gas. Information as to these activities is set forth under Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Market Risk Management – Oil and Natural Gas Derivative Contracts,* and in Note 9, *Commodity Derivative Contracts,* to the Consolidated Financial Statements.

Shortages of oil field equipment, services and qualified personnel could reduce our cash flow and adversely affect results of operations.

The demand for qualified and experienced field personnel, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages in such personnel. In recent years, the competition for qualified technical personnel has been fierce, and our personnel costs have been escalating at a rate higher than general inflation, although it is anticipated that recent oil price declines may slacken this personnel shortage to some degree. In the past, during periods of high oil and natural gas prices, we have experienced shortages of oil field and other necessary equipment, including drilling rigs, along with increased prices for such equipment, services and associated personnel. These types of shortages or price increases could significantly decrease our profit margin, cash flow and operating results and/or restrict or delay our ability to drill wells and conduct our operations, possibly causing us to miss our forecasts and projections.

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

The marketability of our oil and natural gas production depends, in part, upon the availability, proximity and capacity of transportation lines owned by third parties. In general, we do not control these transportation facilities, and our access to them may be limited or denied. A significant disruption in the availability of, and access to, these transportation lines or other production facilities could adversely impact our ability to deliver to market or produce our oil and thereby cause a significant interruption in our operations.

Governmental laws and regulations relating to environmental protection are costly and stringent.

Our exploration, production, and marketing operations are subject to complex and stringent federal, state, and local laws and regulations governing, among other things, the discharge of substances into the environment or otherwise relating to environmental protection, including the protection of endangered species. These laws and regulations and related public policy considerations affect the costs, manner, and feasibility of our operations and require us to make significant expenditures in order to comply. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial obligations, and the issuance of injunctions that could limit or prohibit our operations. In addition, some of these laws and regulations may impose joint and several, strict liability for contamination resulting from spills, discharges, and releases of substances, including petroleum hydrocarbons and other wastes, without regard to fault, or the legality of the original conduct. Under such laws and regulations, we could be required to remove or remediate previously disposed substances and property contamination, including wastes disposed or released by prior owners or operators. Changes in, or additions to, environmental laws and regulations occur frequently, and any changes or additions that result in more stringent and costly waste handling, storage, transport, disposal, cleanup or other environmental protection requirements could have a material adverse effect on our operations and financial position.

Enactment of legislative or regulatory proposals under consideration could negatively affect our business.

Numerous legislative and regulatory proposals affecting the oil and gas industry have been introduced, are anticipated to be introduced, or are otherwise under consideration, by Congress, state legislatures and various federal and state agencies. Among these proposals are: (1) climate change/carbon tax legislation introduced in Congress, and EPA regulations to reduce greenhouse gas emissions; (2) proposals contained in the President's budget, along with legislation introduced in Congress (none of which have passed), to impose new taxes on, or repeal various tax deductions available to, oil and gas producers, such as the current tax deductions for intangible drilling and development costs and qualified tertiary injectant expenses which deductions, if eliminated, could raise the cost of energy production, reduce energy investment and affect the economics of oil and gas exploration and production activities; (3) legislation previously considered by Congress (but not adopted) that would subject the process of hydraulic fracturing to federal regulation under the Safe Drinking Water Act, and new, proposed or anticipated Department of Interior and EPA regulations to impose new and more stringent regulatory requirements on hydraulic fracturing activities, particularly those performed on federal lands, and to require disclosure of the chemicals used in the fracturing process; and (4) the Pipeline Safety, Regulatory Certainty, and Job Creation Act enacted in 2011, which increases penalties, grants new authority to impose damage prevention and incident notification requirements, and directs the PHMSA to prescribe minimum safety standards for CO_2 pipelines. Any of the foregoing described proposals could affect our operations and the costs thereof. The trend toward stricter standards, increased oversight and regulation and more extensive permit requirements, along with any future laws and regulations, could result in increased costs or additional operating restrictions that could have an effect on demand for oil and natural gas or prices at which it can be sold. However, until such legislation or regulations are enacted or adopted into law and thereafter implemented, it is not possible to gauge their impact on our future operations or our results of operations and financial condition.

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

In recent years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of certain U.S. federal income tax benefits and deductions currently available to oil and gas companies. Such changes include, but are not limited to, (1) the repeal of the percentage depletion allowance for oil and gas properties, (2) the increase of the amortization period of geological and geophysical expenses, (3) the elimination of current deductions for intangible drilling and development costs and qualified tertiary injectant expenses, and (4) the elimination of the deduction for certain U.S. production activities. It is currently unclear whether any such proposals will be enacted into law and, if so, what form such laws might possibly take or impact they may have; however, the passage of such legislation or any other similar change in U.S. federal income tax law could eliminate, reduce or postpone certain tax deductions that are currently available to us, and any such legislation or change could negatively affect the after-tax returns generated on our oil and gas investments and our financial condition and results of operations.

The derivatives market regulations promulgated under the Dodd-Frank Act could have an adverse effect on our ability to hedge risks associated with our business.

The Dodd-Frank Act requires the Commodities Futures Trading Commission (“CFTC”) and the SEC to promulgate rules and regulations establishing federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market, including swap clearing and trade execution requirements. Our derivative transactions are not currently subject to such swap clearing and trade execution requirements; however, in the event our derivative transactions potentially become subject to such requirements, we believe that our derivative transactions would qualify for the “end-user” exception. New or modified rules, regulations or requirements may increase the cost to our counterparties of their hedging and swap positions that they can provide or lower their availability. In addition, for uncleared swaps, the CFTC or federal banking regulators may require end-users to enter into credit support documentation or post margin collateral. Any changes in the regulations of swaps may result in certain market participants deciding to curtail or cease their derivative activities.

While many rules and regulations have been promulgated and are already in effect, other rules and regulations remain to be finalized or effectuated; therefore, the impact of those rules and regulations on us is uncertain at this time. The Dodd-Frank Act, and the rules promulgated thereunder, could (1) significantly increase the cost, or decrease the liquidity, of energy-related derivatives we use to hedge against commodity price fluctuations (including through requirements to post collateral), (2) materially alter the terms of derivative contracts, (3) reduce the availability of derivatives to protect against risks we encounter, and (4) increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and applicable rules and regulations, our cash flows may become more volatile and less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

The loss of one or more of our large oil and natural gas purchasers could have an adverse effect on our operations.

For the year ended December 31, 2014, three purchasers individually accounted for 10% or more of our oil and natural gas revenues and, in the aggregate, for 56% of such revenues. The loss of a large single purchaser could adversely impact the prices we receive or the transportation costs we incur.

Certain of our operations may be limited during certain periods due to severe weather conditions and other regulations.

Certain of our operations in North Dakota, Montana and Wyoming, including the construction of CO_2 pipelines, the drilling of new wells and production from existing wells, are conducted in areas subject to extreme weather conditions, including severe cold, snow and rain, which conditions may cause such operations to be hindered or delayed, or otherwise require that they be conducted only during non-winter months, and depending on the severity of the weather, could have a negative effect on our results of operations in these areas. Further, certain of our operations in these areas are confined to certain time periods due to environmental regulations, federal restrictions on when drilling can take place on federal lands, and lease stipulations designed to protect certain wildlife, which regulations, restrictions and limitations could slow down our operations, cause delays, increase costs and have a negative effect on our results of operations.

Our results of operations could be negatively affected as a result of goodwill or long-lived asset impairments.

At December 31, 2014, our goodwill balance totaled $1.3 billion and our net property and equipment balance totaled $10.4 billion, representing approximately 10% and 81%, respectively, of our total assets. Goodwill is not amortized; rather it is tested for impairment annually during the fourth quarter and when facts or circumstances indicate that the carrying value of our goodwill may be impaired, requiring an estimate of the fair values of the reporting unit's assets and liabilities. Our oil and natural gas properties balance is subject to our quarterly full cost pool ceiling test, and other long-lived assets are required to be tested for impairment when events or circumstances indicate the carrying value may not be recoverable. An impairment of goodwill or long-lived assets could significantly reduce earnings during the period in which the impairment occurs and would result in a corresponding reduction to goodwill or long-lived assets and equity. See Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies and Estimates – Impairment Assessment of Goodwill.*

We may lose executive officers or other key management personnel, which could endanger the future success of our operations.

Our success depends to a significant degree upon the continued contributions of our executive officers and other key management personnel. Our employees, including our executive officers, are employed at will and do not have employment agreements. If one or more members of our management team dies, becomes disabled or voluntarily terminates employment with us, there is no assurance that we will find a suitable or comparable substitute. We believe that our future success depends, in large part, upon our ability to hire and retain highly skilled managerial personnel. Competition for persons with these skills is intense, and we cannot assure that we will be successful in attracting and retaining such skilled personnel. For example, we are currently conducting a search to fill two vacant executive-level operations positions, but there is no guarantee we can quickly fill them with personnel of our desired skill set. The continued vacancy in these positions or an additional loss of any of our management personnel could adversely affect our operations.

A cyber incident could occur and result in information theft, data corruption, operational disruption, and/or financial loss.

Our business has become increasingly dependent on digital technologies to conduct day-to-day operations, including certain of our exploration, development and production activities. We depend on digital technology to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information and in many other activities related to our business. Our technologies, systems and networks may become the target of cyber attacks or information security breaches that could result in the disruption of our business operations. For example, unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in our drilling or production operations, which could cause financial loss.

Although we utilize various procedures and controls to monitor and protect against these threats and to mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing and causing us to suffer such losses in the future. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our procedures and controls or to investigate and remediate any cyber vulnerabilities.

Item 1B. Unresolved Staff Comments

There are no unresolved written SEC staff comments regarding our periodic or current reports under the Securities Exchange Act of 1934 received 180 days or more before the end of the fiscal year to which this annual report on Form 10-K relates.

Item 2. Properties

Information regarding the Company's properties called for by this item is included in Item 1, *Business and Properties – Oil and Natural Gas Operations.* We also have various operating leases for rental of office space, office and field equipment, and vehicles. See Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Off-Balance Sheet Agreements,* and Note 11, *Commitments and Contingencies,* to the Consolidated Financial Statements for the future minimum rental payments. Such information is incorporated herein by reference.

Item 3. Legal Proceedings

We are involved in various lawsuits, claims and regulatory proceedings incidental to our businesses. While we currently believe that the ultimate outcome of these proceedings, individually and in the aggregate, will not have a material adverse effect on our consolidated financial position or overall trends in results of operations or cash flows, litigation is subject to inherent uncertainties. If an unfavorable ruling in one of these lawsuits or proceedings were to occur, there exists the possibility of a material adverse impact on our net income in the period in which the ruling occurs. We provide accruals of probable losses for litigation and claims if we determine that we may have a range of legal exposure that would require accrual.

Item 4. Mine Safety Disclosures

Not applicable.

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

Common Stock Trading Summary

The following table summarizes the high and low reported sales prices on days in which there were trades of Denbury's common stock on the New York Stock Exchange ("NYSE") for each quarterly period for the last two fiscal years, as well as dividends declared within those periods. Prior to 2014, we had not historically declared or paid dividends on our common stock. As of January 31, 2015, based on information from the Company's transfer agent, American Stock Transfer and Trust Company, the number of holders of record of Denbury's common stock was 1,772. On February 26, 2015, the last reported sale price of Denbury's common stock, as reported on the NYSE, was $8.38 per share.

	2014			2013		
	High	Low	Dividends Declared Per Share	High	Low	Dividends Declared Per Share
First Quarter	$16.44	$15.33	$0.0625	$19.11	$16.50	$ —
Second Quarter	18.31	16.14	0.0625	19.48	16.68	—
Third Quarter	18.12	14.93	0.0625	18.55	16.90	—
Fourth Quarter	14.41	6.34	0.0625	19.44	15.98	—

On January 27, 2015, the Board of Directors declared a dividend of $0.0625 per share on our common stock, payable on March 31, 2015, to stockholders of record at the close of business on February 24, 2015. While we currently expect to continue to pay a regular quarterly dividend on our common stock, the declaration and payment of future dividends are at the discretion of our Board of Directors, and the amount thereof will depend on our results of operations, financial condition, capital requirements, level of indebtedness, market conditions, and other factors deemed relevant by the Board of Directors. Our Bank Credit Agreement and senior subordinated note indentures require us to meet certain financial covenants at the time dividend payments are made. For further discussion, see Note 5, *Long-Term Debt,* to the Consolidated Financial Statements. No unregistered securities were sold by the Company during 2014.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Month	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in millions) (2)
October 2014	3,737	$12.89	—	$221.9
November 2014	5,359	10.79	—	221.9
December 2014	66,602	8.25	—	221.9
Total	75,698		—	

(1) Stock repurchases during the fourth quarter of 2014 were made in connection with delivery by our employees of shares to us to satisfy their tax withholding requirements related to the vesting of restricted shares and the exercise of stock appreciation rights.

(2) In October 2011, the Company's Board of Directors approved a common share repurchase program for up to $500 million of Denbury's common stock. During 2012 and 2013, the Board of Directors increased the dollar amount of Denbury common shares that could be purchased under the program to an aggregate of up to $1.162 billion. The program has no pre-established ending date and may be suspended or discontinued at any time. In November 2014, the Company's Board of Directors suspended the common share repurchase program in light of commodity price uncertainty in order to protect our financial strength and preserve liquidity. We are not obligated to repurchase any dollar amount or specific number of shares of our common stock under the program.

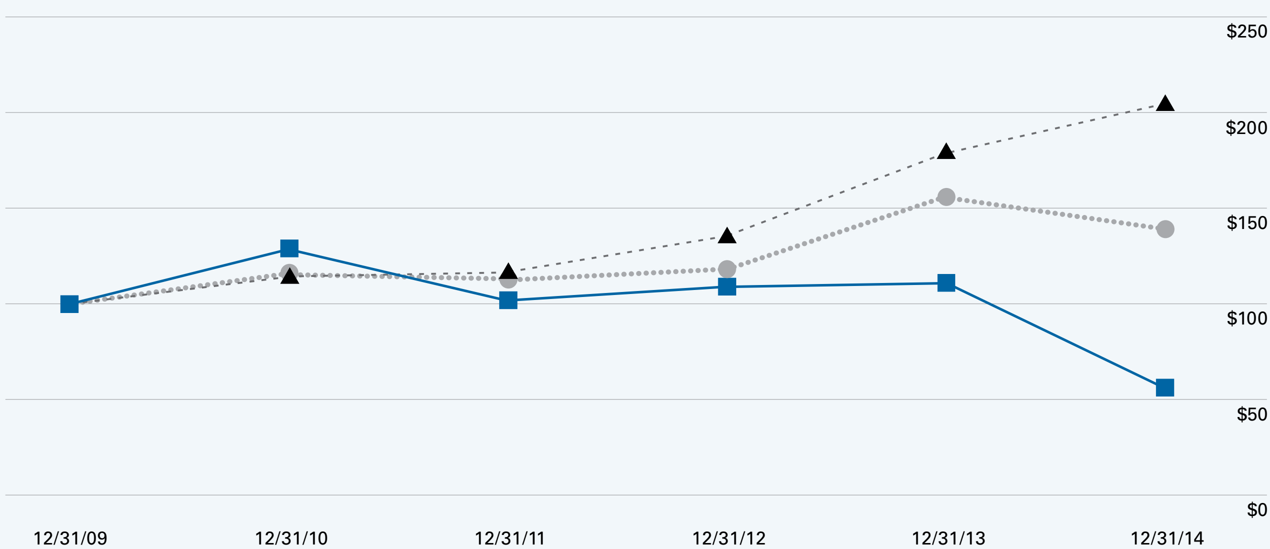
Between early October 2011, when we announced the commencement of a common share repurchase program, and December 31, 2014, we repurchased 60.0 million shares of Denbury common stock (approximately 14.9% of our outstanding shares of common stock at September 30, 2011) for $940.0 million, or $15.68 per share.

Share Performance Graph

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

The following graph illustrates changes over the five-year period ended December 31, 2014, in cumulative total stockholder return on our common stock as measured against the cumulative total return of the S&P 500 Index and the Dow Jones U.S. Exploration and Production Index. The graph tracks the performance of a $100 investment in our common stock and in each index (with the reinvestment of all dividends for the index securities) from December 31, 2009, to December 31, 2014.

Comparison of 5-Year Cumulative Total Return



	December 31, 2009	2010	2011	2012	2013	2014
Denbury Resources Inc.	$100	$129	$102	$109	$111	$ 56
S&P 500	100	115	117	136	180	205
Dow Jones U.S. Exploration and Production	100	117	112	118	156	139

Item 6. Selected Financial Data

In thousands, except per-share data or otherwise noted	Year Ended December 31, 2014	2013	2012	2011	2010 [1]
Consolidated Statements of Operations data					
Revenues and other income					
Oil, natural gas, and related product sales	$ 2,372,473	$ 2,466,234	$ 2,409,867	$ 2,269,151	$ 1,793,292
Other	62,732	50,893	46,605	40,173	128,499
Total revenues and other income	$ 2,435,205	$ 2,517,127	$ 2,456,472	$ 2,309,324	$ 1,921,791
Net income attributable to Denbury stockholders	635,491	409,597	525,360	573,333	271,723
Net income per common share					
Basic	1.82	1.12	1.36	1.45	0.73
Diluted	1.81	1.11	1.35	1.43	0.72
Dividends declared per common share	0.25	—	—	—	—
Weighted average number of common shares outstanding					
Basic	348,962	366,659	385,205	396,023	370,876
Diluted	351,167	369,877	388,938	400,958	376,255
Consolidated Statements of Cash Flows data					
Cash provided by (used in)					
Operating activities	$ 1,222,825	$ 1,361,195	$ 1,410,891	$ 1,204,814	$ 855,811
Investing activities	(1,076,755)	(1,275,309)	(1,376,841)	(1,605,958)	(354,780)
Financing activities	(135,104)	(172,210)	45,768	37,968	(139,753)
Production (average daily)					
Oil (Bbls)	70,606	66,286	66,837	60,736	59,918
Natural gas (Mcf)	22,955	23,742	29,109	29,542	78,057
BOE (6:1)	74,432	70,243	71,689	65,660	72,927
Unit sales prices – excluding impact of derivative settlements					
Oil (per Bbl)	$ 90.74	$ 100.67	$ 97.18	$ 100.03	$ 75.97
Natural gas (per Mcf)	4.07	3.53	3.05	4.79	4.63
Unit sales prices – including impact of derivative settlements					
Oil (per Bbl)	$ 90.82	$ 100.64	$ 96.77	$ 98.90	$ 71.69
Natural gas (per Mcf)	3.99	3.53	5.67	7.34	6.45
Costs per BOE					
Lease operating expenses [2]	$ 23.84	$ 28.50	$ 20.29	$ 21.17	$ 17.67
Taxes other than income	6.25	6.87	6.10	6.16	4.53
General and administrative expenses	5.83	5.66	5.49	5.24	5.04
Depletion, depreciation, and amortization	21.83	19.89	19.34	17.07	16.32
Proved oil and natural gas reserves [3]					
Oil (MBbls)	362,335	386,659	329,124	357,733	338,276
Natural gas (MMcf)	452,402	489,954	481,641	625,208	357,893
MBOE (6:1)	437,735	468,318	409,398	461,934	397,925
Proved carbon dioxide reserves					
Gulf Coast region (MMcf) [4]	5,697,642	6,070,619	6,073,175	6,685,412	7,085,131
Rocky Mountain region (MMcf) [5]	3,035,286	3,272,428	3,495,534	2,195,534	2,189,756
Proved helium reserves associated with Denbury's production rights [6]					
Rocky Mountain region (MMcf)	13,231	13,251	12,712	12,004	7,159
Consolidated Balance Sheets data					
Total assets	$12,727,802	$11,788,737	$11,139,342	$10,184,424	$9,065,063
Total long-term liabilities	6,383,821	5,812,132	5,408,032	4,716,659	4,105,011
Stockholders' equity	5,703,856	5,301,406	5,114,889	4,806,498	4,380,707

(1) On March 9, 2010, we acquired Encore Acquisition Company ("Encore"). We consolidated Encore's results of operations beginning March 9, 2010.

(2) If lease operating expenses and related insurance recoveries recorded in 2013 and 2014 to remediate an area of Delhi Field were excluded, lease operating expenses would have totaled $654.7 million and $616.6 million for the years ended December 31, 2014 and 2013, respectively, and lease operating expenses per BOE would have averaged $24.10 and $24.05 for the years ended December 31, 2014 and 2013, respectively (see *Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Insurance Recoveries to Cover Costs of 2013 Delhi Field Release).*

(3) Estimated proved reserves as of December 31, 2012, reflect the disposition of reserves associated with our Bakken area assets sold in late 2012 (approximately 109 MMBOE), but do not include then-estimated reserves of approximately 42.2 MMBOE related to the CCA acquisition from ConocoPhillips, which closed during the first quarter of 2013. See Note 2, *Acquisition,* to the Consolidated Financial Statements for further discussion of the CCA acquisition.

(4) Proved CO_2 reserves in the Gulf Coast region consist of reserves from our reservoirs at Jackson Dome and are presented on a gross or 8/8ths working interest basis, of which our net revenue interest was approximately 4.5 Tcf, 4.8 Tcf, 4.8 Tcf, 5.3 Tcf and 5.6 Tcf at December 31, 2014, 2013, 2012, 2011 and 2010, respectively, and include reserves dedicated to volumetric production payments of 9.3 Bcf, 28.9 Bcf, 57.1 Bcf, 84.7 Bcf and 100.2 Bcf at December 31, 2014, 2013, 2012, 2011 and 2010, respectively. (See *Supplemental CO_2 and Helium Disclosures (Unaudited)* to the Consolidated Financial Statements.)

(5) Proved CO_2 reserves in the Rocky Mountain region consist of our reserves at Riley Ridge (presented on a gross working interest basis) and our overriding royalty interest in LaBarge Field, of which our net revenue interest was approximately 2.6 Tcf, 2.9 Tcf, 2.9 Tcf, 1.6 Tcf and 0.9 Tcf at December 31, 2014, 2013, 2012, 2011 and 2010, respectively.

(6) Reserves associated with helium production rights include helium reserves located in the acreage in the Rocky Mountain region for which we have the contractual right to extract the helium on behalf of the U.S. government, which owns the helium. Our extraction agreement with the U.S. government gives us the ability to produce the helium on behalf of the U.S. government in exchange for a fee, which amount fluctuates based upon the realized sales proceeds we receive for the helium. The estimate of helium reserves is reduced to reflect the estimated fee we will remit to the U.S. government. Our extraction agreement with the U.S. government has a minimum term extending 20 years from first production and continuing thereafter until either party terminates the contract. Reserve volumes presented herein assume that the term of this helium extraction agreement continues beyond 20 years, given the benefit to both parties to the agreement. As of December 31, 2014, there was no helium production at Riley Ridge, as the Riley Ridge gas processing facility is shut-in, which we currently expect will continue until 2016.

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

The following discussion and analysis should be read in conjunction with our Consolidated Financial Statements and Notes thereto included in Item 8, *Financial Statements and Supplementary Information*. Our discussion and analysis includes forward-looking information that involves risks and uncertainties and should be read in conjunction with *Risk Factors* under Item 1A of this Form 10-K, along with *Forward-Looking Information* at the end of this section for information on the risks and uncertainties that could cause our actual results to be materially different from our forward-looking statements.

OVERVIEW

Denbury is an independent oil and natural gas company with operations focused in two key operating areas: the Gulf Coast and Rocky Mountain regions. Our goal is to increase the value of our properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis relating to CO_2 enhanced oil recovery operations.

2014 Operating Highlights. During 2014, we recognized net income of $635.5 million, or $1.81 per diluted common share, compared to net income of $409.6 million, or $1.11 per diluted common share, during 2013. This increase in net income between the comparative periods was principally due to a $596.3 million (pre-tax) positive change in commodity derivatives expense (income) between the two periods (principally due to a $594.2 million noncash increase in the fair value of our derivatives). Our higher income in 2014 is further attributable to an $83.0 million (pre-tax) decrease in lease operating expenses, as 2013 included Delhi remediation charges of $114.0 million (pre-tax), compared to a net reduction of lease operating expenses of $7.1 million (pre-tax) in 2014 due primarily to partial insurance recoveries received related to the same remediation. Partially offsetting these favorable items was a $93.8 million (pre-tax) decrease in oil, natural gas, and related product sales, driven by a 10% decrease in our realized oil price between the two periods offset in part by a 6% increase in production, a $69.3 million (pre-tax) increase in the loss on early extinguishment of debt, and a $42.3 million (pre-tax) increase in interest expense, primarily driven by a decrease in capitalized interest. These matters are further described throughout this Management's Discussion and Analysis.

During 2014, our oil and natural gas production, which was 95% oil, averaged 74,432 BOE/d, compared to an average of 70,243 BOE/d produced during 2013. This 6% increase in production was primarily due to a 7% increase in our tertiary oil production in 2014 and our receiving only nine months of production in 2013 from the purchase of additional interests in the Cedar Creek Anticline ("CCA") in late March 2013.

Our average realized oil price per barrel, excluding the impact of commodity derivative contracts, was $90.74 per Bbl during 2014, a decrease of 10% compared to $100.67 per Bbl realized during 2013. The oil price we realized relative to NYMEX oil prices (our NYMEX oil price differential) was $2.21 per Bbl below NYMEX prices during 2014, a $4.83 per Bbl decrease compared to prices of $2.62 per Bbl above NYMEX in 2013, driven by a decrease in the Light Louisiana Sweet ("LLS") index premium in 2014 and an increase in the Rocky Mountain region discount in 2014 relative to NYMEX oil prices.

In recent years, and particularly during 2013, we have experienced gradually rising costs. As a result, one of our primary focuses in 2014 was to reduce costs throughout the organization, through a number of internal initiatives. For example, excluding Delhi remediation costs and insurance reimbursements and unplanned Riley Ridge well workovers, our recurring lease operating expenses per BOE decreased each sequential quarter in 2014 and decreased a total of 14% between the fourth quarter of 2013 and the fourth quarter of 2014, with the decrease in workover costs the primary component of lease operating expense cost reductions. Our goal is to continue to reduce both capital project costs and per-barrel operating costs, and we believe such reductions are possible, especially in light of the recent decline in oil prices.

Proved Oil and Natural Gas Reserves. Our estimated proved oil and gas reserves were 437.7 MMBOE as of December 31, 2014, compared to 468.3 MMBOE at December 31, 2013. The net reduction of total proved reserves of 30.6 MMBOE during 2014 was primarily the result of 27.2 MMBOE of current-year production and the absence of any meaningful reserve extensions or discoveries in 2014, as there were no significant new CO_2 EOR floods initiated in 2014.

April 2014 Debt Refinancing. On April 30, 2014, we issued $1.25 billion of 5½% Senior Subordinated Notes due 2022 (the "5½% Notes"). The net proceeds of $1.23 billion were used to repurchase and redeem all $996.3 million of our outstanding 8¼% Senior Subordinated Notes due 2020 (the "8¼% Notes"), which were issued in 2010, and to pay down approximately $150 million of outstanding borrowings on our bank credit facility. This refinancing provides for ongoing net annual interest savings of approximately $17 million. Due to the refinancing, we recognized a loss on extinguishment of debt of $113.9 million (principally related to the tender or redemption premium on the 8¼% Notes repurchased) during the second quarter of 2014.

Recent Oil Price Decline and Impact on Our Business. Although oil prices have historically been volatile, during the second half of 2014 and continuing into 2015, oil prices dropped rapidly, with NYMEX prices declining from $107 per Bbl in June 2014 to less than $54 per Bbl in late December 2014, and further declining to below $45 per Bbl in January 2015. In response to the decline in oil prices during the latter part of 2014, in November 2014 we announced a significant reduction in our capital spending plans, reducing projected 2015 capital spending to $550 million, or roughly half of 2014 levels, and decreasing our estimated dividend rate for 2015 to $0.40 per common share on an annualized basis, from the previous projection of a rate ranging between $0.50 per common share to $0.60 per common share on an annualized basis. At the same time, we announced that our share repurchase program was being suspended in order to protect our financial health and preserve liquidity amid a period of declining oil prices and overall oil price uncertainty. As a result of further oil price declines in late 2014 and early 2015, in January 2015, we announced another change in our planned 2015 dividend rate, as the Company's Board of Directors declared a dividend of $0.0625 per common share for the first quarter of 2015, or $0.25 per common share on an annualized basis, a level consistent with our 2014 dividend rate.

Oil prices generally constitute the largest single variable in our operating results. For the past several years, we have employed a strategy of hedging a substantial portion of our forecasted production, approximately 18 months to two years into the future (from the then-current quarter), to mitigate the risks associated with fluctuations during periods of oil price declines. For 2015, we have hedges covering approximately 70% to 75% of our forecasted oil production, which will help to diminish the impact of the significant oil price drop on our 2015 cash flows and operating results; however, to the extent our production is unhedged, we are fully exposed to the decline in oil prices. For the fourth quarter of 2015 and 2016, we have significantly fewer hedges, and thus, the impact of low oil prices on our cash flows and operating results will be more impactful unless oil prices increase. See *Results of Operations – Commodity Derivative Contracts* and Note 9, *Commodity Derivative Contracts,* to the Consolidated Financial Statements for additional information regarding our commodity derivative contracts.

CAPITAL RESOURCES AND LIQUIDITY

Overview. Our primary sources of capital and liquidity are our cash flows from operations and availability for borrowings under our bank credit facility. Our business is capital intensive, and it is common for oil and natural gas companies our size to reinvest most or all of their cash flow into developing new assets. We generally attempt to balance our capital expenditures and dividends with cash flows from operations, and during 2014, we spent a combined $1.2 billion on capital expenditures and dividends while generating $1.2 billion of cash flows from operations. Our 2014 cash flow from operations was lower than the $1.4 billion generated in 2013, due primarily to lower oil prices, which caused a decrease in oil revenues and changes in working capital items.

As discussed in the *Overview* above, we have been proactive in adjusting our 2015 capital spending and dividend plans in connection with the current lower oil price environment. We project that we will have adequate capital resources and liquidity for the foreseeable future because (1) we have significant borrowing capacity on our bank line and recently extended its maturity to December 2019; (2) we have commodity derivative contracts in place to cover a significant portion of our forecasted oil production for 2015 that will lessen the impact of the current lower oil price environment (see Note 9, *Commodity Derivative Contracts,* to the Consolidated Financial Statements for further details regarding the prices and volumes of our commodity derivative contracts); (3) generally, we plan to fund both our projected capital expenditures and dividends with cash flows from operations; (4) we can significantly reduce our capital expenditures for extended periods of time if necessary, due to lower cash flows, and still maintain relatively flat or slightly lower production levels as a result of the unique characteristics of CO_2 EOR operations; and (5) the maturity dates of all but a minor amount of our senior subordinated notes extend seven years or more, including the new 5½% Notes issued in connection with the April 2014 debt refinancing (discussed above), and carry attractive fixed interest rates ranging between 4⅝% and 6⅜%.

If oil prices remain at relatively low levels beyond 2015, our cash flows from operations will likely be significantly lower than current levels, as our oil hedges presently in place for 2016 cover significantly less forecasted oil production. Therefore, we are currently focused on reducing our operating costs so as to preserve as much of our operating margin as possible in this lower oil price environment, and if this low oil price environment persists, we intend to continue to make adjustments to our capital spending plans to preserve our financial health. Fortunately, some of our costs, such as our CO_2 purchases, adjust proportionally with changes in the price of oil. We also expect that our cost of services and equipment will come down in this lower oil price environment, but this may take time and may not reflect as large a percentage decrease as the decrease in the price of oil. Although we can reduce capital spending and maintain production at relatively flat or slightly lower production levels for some time, we can do this for only a limited period of time before our production will begin to decline significantly, which will further lower our cash flow from operations. Further, if this lower oil price environment continues into 2016, we may be required to amend our debt to EBITDAX covenant under our bank credit agreement, which amendment we believe we can obtain, although it may restrict some of the financial flexibility we currently have (see further discussion in Note 5, *Long-Term Debt,* to the Consolidated Financial Statements and *Bank Credit Facility* below).

2015 Capital Spending. We anticipate that our 2015 capital budget, excluding acquisitions, will be $550 million, which includes approximately $85 million in capitalized internal acquisition, exploration and development costs; capitalized interest; and pre-production startup costs associated with new tertiary floods. This combined 2015 capital budget amount, excluding acquisitions, compares to combined 2014 capital spending of $1.1 billion (see *Capital Expenditure Summary* below for a summary of actual 2014 expenditures). The 2015 capital budget is comprised of the following:

- $320 million allocated for tertiary oil field expenditures;
- $100 million allocated for other areas, primarily non-tertiary oil field expenditures;
- $30 million to be spent on CO_2 sources;
- $15 million for pipeline construction; and
- $85 million for other capital items such as capitalized internal acquisition, exploration and development costs; capitalized interest; and pre-production startup costs associated with new tertiary floods.

Based on oil and natural gas commodity futures prices in early February 2015, our current production forecast, and our commodity derivative contracts covering a substantial portion of our anticipated 2015 production, we believe our anticipated 2015 cash flows from operations should be adequate to cover our combined 2015 capital budget and currently planned dividend payments. If prices were to decrease further or changes in operating results were to cause us to have a reduction in anticipated 2015 cash flows below our currently forecasted operating cash flows, we would likely further reduce our capital expenditures or reduce our targeted dividend payment, with ample availability on our bank credit facility to cover any potential shortfall. If we further reduce our capital spending due to lower cash flows, any sizeable reduction could lower our anticipated production levels in future years.

Stock Repurchase Program. In November 2014, the Company's Board of Directors suspended our common share repurchase program in light of commodity price uncertainty and in order to protect our financial strength and preserve liquidity. As of December 31, 2014, we had spent $940.0 million since inception of this program to repurchase 60.0 million shares of our common stock under this program (approximately 14.9% of our outstanding shares at September 30, 2011). See Note 7, *Stockholders' Equity,* to the Consolidated Financial Statements for further discussion.

Dividends. During 2014 we paid aggregate cash dividends of $87.0 million to holders of our outstanding common stock at a quarterly rate of $0.0625 per outstanding common share, or an annual rate of $0.25 per common share. See Note 14, *Subsequent Events,* to the Consolidated Financial Statements for details regarding the dividend declared in the first quarter of 2015. The declaration and payment of future dividends are at the discretion of our Board of Directors, and the amount thereof will depend on our results of operations, financial condition, capital requirements, level of indebtedness, market conditions, and other factors deemed relevant by the Board of Directors.

Insurance Recoveries to Cover Costs of 2013 Delhi Field Release. We completed our remediation efforts related to the release of well fluids at the Denbury-operated Delhi Field during the fourth quarter of 2013. During the year ended December 31, 2014, we recorded an additional $16.8 million of lease operating expenses related to this release and its remediation in our Consolidated Statements of Operations, which brings our total cost estimate to date with respect to these expenses to $130.8 million, of which we have paid $112.6 million. The $16.8 million of additional charges in 2014 primarily consist of our actual or estimated expenses related to third-party property and commercial damage claims that have been settled or asserted in connection with the release, which are expected to be recoverable under our insurance policies.

We maintain insurance policies to cover certain costs, damages and claims related to releases of well fluids and remediation. In October 2014 we received a $25.0 million cost reimbursement ($23.9 million net to Denbury) related to the Delhi Field release and remediation from our insurance carrier providing the first layer of our excess insurance coverage, representing approximately 20% of our total incident costs through year-end 2014. The insurance reimbursement was recognized as a reduction to lease operating expenses in our Consolidated Statements of Operations for the year ended December 31, 2014. We have not reached any agreement with our remaining carriers as to further reimbursements, but given our belief that under our policies we are entitled to reimbursement of between approximately one-third and two-thirds of our total costs, we have filed suit to pursue further reimbursements, the ultimate outcome of which cannot be predicted.

Bank Credit Facility. We amended our bank credit facility in December 2014 to replace our previous credit agreement that was set to mature in May 2016. The amended bank credit facility has a maturity date of December 9, 2019, an initial borrowing base of $3.0 billion, and aggregate lender commitments of $1.6 billion (the “Bank Credit Facility”). The Company elected to maintain the aggregate lender commitments at $1.6 billion to be consistent with the Company’s prior facility, and as of December 31, 2014, we had availability of approximately $1.2 billion with respect to such lender commitments. The Bank Credit Facility provides for an annual redetermination of the borrowing base around May 1 of each year and permits us to increase the aggregate lender commitments up to the borrowing base amount with approval and incremental commitments from the existing lenders or new lenders. The new facility reduced our borrowing costs by 25 basis points on the drawn spread and provided for a lower interest rate on the undrawn spread. Based on the current value of our proved reserves assessed by the banks using their pricing assumptions, we currently do not anticipate a near-term reduction in our borrowing base below our aggregate lender commitments of $1.6 billion. However, the borrowing base is subject to lender discretion and may be reduced in future periods depending upon future oil prices and the banks’ pricing assumptions. The Bank Credit Facility is secured by a significant portion of our proved oil and natural gas properties.

Our Bank Credit Facility contains certain restrictive covenants, plus two principal financial performance covenants to maintain a ratio of consolidated total net debt to consolidated EBITDAX of not more than 4.25 to 1.0 and a current ratio of not less than 1.0 (all terms as defined in the bank credit agreement). For these financial performance covenant calculations as of December 31, 2014, our ratio of consolidated total net debt to consolidated EBITDAX was 2.52 to 1.0, and our current ratio was 2.45. Although we are currently in compliance with these financial performance covenants and project to be in compliance with the covenants through 2015 based on our current projections of production and current oil futures prices, if oil prices were to continue to decline or remain at low levels for an extended period of time, we may not be able to meet the consolidated total net debt to consolidated EBITDAX covenant in late 2015 or more likely in 2016. Failure to comply with this or other covenants could lead to a default under the Bank Credit Facility, requiring us to seek a waiver, renegotiate terms of the agreement or repay outstanding borrowings, although we believe it is likely that we could restructure our consolidated total net debt to consolidated EBITDAX covenant, if necessary, and/or receive a waiver for any default. See further discussion in Item 1A, *Risk Factors*.

Capital Expenditure Summary. The following table summarizes our 2014, 2013 and 2012 capital expenditures incurred by project area, including accrued capital expenditures:

	Year Ended December 31,		
In thousands	2014	2013	2012
Capital expenditures by project			
Tertiary oil fields	$ 629,790	$ 534,878	$ 449,226
Non-tertiary fields	240,187	224,556	543,162
Capitalized interest and internal costs (1)	89,716	114,197	93,663
Oil and natural gas capital expenditures	959,693	873,631	1,086,051
CO_2 pipelines	45,672	57,136	181,873
CO_2 sources (2)	56,460	163,710	238,613
CO_2 capitalized interest and other	4,247	49,021	47,628
Capital expenditures, before acquisitions	1,066,072	1,143,498	1,554,165
Less: recoveries from sale/leaseback transactions	—	—	(35,102)
Net capital expenditures, excluding acquisitions	1,066,072	1,143,498	1,519,063
Property acquisitions (3)	8,773	1,032,218	942,359
Capital expenditures, net of sale/leaseback transactions	$1,074,845	$2,175,716	$2,461,422

(1) Includes capitalized internal acquisition, exploration and development costs; capitalized interest; and pre-production startup costs associated with new tertiary floods.

(2) Includes capital expenditures related to the Riley Ridge gas processing facility.

(3) Property acquisitions during the years ended December 31, 2013 and 2012 include capital expenditures of approximately $1.0 billion and $0.2 billion, respectively, related to acquisitions during the period that are not reflected as an Investing Activity on our Consolidated Statements of Cash Flows due to the movement of proceeds through a qualified intermediary to facilitate like-kind-exchange treatment under federal income tax rules. In addition, property acquisitions in 2012 shown above include capital expenditures of approximately $0.6 billion representing the aggregate fair value of net assets acquired, excluding cash, in the late-2012 sale and exchange transaction with Exxon Mobil Corporation and its wholly-owned subsidiary XTO Energy Inc. (the “Bakken Exchange Transaction”). See Note 2, *Acquisition*, to the Consolidated Financial Statements.

Our 2014 capital expenditures were fully funded with $1.2 billion of cash flow from operations. Our 2013 capital expenditures, other than those for property acquisitions, were funded with $1.4 billion of cash flow from operations, and those for property acquisitions were funded with proceeds from the Bakken Exchange Transaction. Our 2012 capital expenditures were funded primarily with $1.4 billion of cash flow from operations, and our property acquisitions were funded with proceeds from the sale of non-core assets and the Bakken Exchange Transaction

Commitments and Obligations. A summary of our obligations at December 31, 2014, is presented in the following table:

	Payments Due by Period				
In thousands	2015	2016 and 2017	2018 and 2019	Thereafter	Total
Contractual obligations					
Bank Credit Agreement	$ —	$ —	$ 395,000	$ —	$ 395,000
Estimated interest payments on					
Bank Credit Facility and subordinated debt	161,268	322,145	321,159	398,417	1,202,989
Subordinated debt	485	2,250	—	2,850,000	2,852,735
Operating lease obligations	12,556	25,306	23,933	56,630	118,425
Pipeline and capital lease obligations	61,225	117,978	98,043	237,473	514,719
Other obligations (1)	73,905	190,763	185,467	658,284	1,108,419
Asset retirement obligations (2)	2,046	—	2,276	691,222	695,544
Total contractual obligations	$311,485	$658,442	$1,025,878	$4,892,026	$6,887,831

(1) Represents future cash commitments under contracts in place as of December 31, 2014, primarily for purchase contracts for CO_2 captured from industrial sources, drilling rig services and well-related costs. As is common in our industry, we commit to make certain expenditures on a regular basis as part of our ongoing development and exploration program. These commitments generally relate to projects that occur during the subsequent several months and are usually part of our normal operating expenses or part of our capital budget (see *2015 Capital Spending* above). We also have recurring expenditures for such things as accounting, engineering and legal fees; software maintenance; subscriptions; and other overhead-type items. Normally these expenditures do not change materially on an aggregate basis from year to year and are part of our general and administrative expenses. We have not attempted to estimate the amounts of these types of recurring expenditures in this table, as most could be quickly canceled with regard to any specific vendor, even though the expense itself may be required for our ongoing normal operations. For further discussion of our long-term commitments to purchase CO_2, see Note 11, *Commitments and Contingencies,* to the Consolidated Financial Statements.

(2) Represents the estimated future asset retirement obligations on an undiscounted basis. The present value of the discounted asset retirement obligation is $128.1 million, as determined under the *Asset Retirement and Environmental Obligations* topic of the Financial Accounting Standards Board Codification ("FASC"), and is further discussed in Note 3, *Asset Retirement Obligations,* to the Consolidated Financial Statements.

Off-Balance Sheet Arrangements. We have several operating leases relating to office space and other minor equipment leases. At December 31, 2014, we had a total of $11.3 million of letters of credit outstanding under our Bank Credit Facility. Additionally, we have obligations that are not currently recorded on our balance sheet relating to various obligations for development and exploratory expenditures that arise from our normal capital expenditure program or from other transactions common to our industry. These obligations are further described in *Commitments and Obligations* above. In addition, in order to recover our undeveloped proved reserves, we must also fund the associated future development costs estimated in our proved reserve reports. For a further discussion of our future development costs, see *Supplemental Oil and Natural Gas Disclosures (Unaudited)* to the Consolidated Financial Statements.

FINANCIAL OVERVIEW OF TERTIARY OPERATIONS

As discussed in Item 1, *Business and Properties – Oil and Natural Gas Operations – Enhanced Oil Recovery Overview* above, our tertiary operations represent a significant portion of our overall operations and have become our primary strategic focus. The economics of a tertiary field and the related impact on our financial statements differ from a conventional oil and gas play and are explained further below.

While it is difficult to accurately forecast future production, we believe our tertiary recovery operations provide significant long-term production growth potential at reasonable rates of return, with relatively low risk. Our rate of return from our tertiary operations has generally been higher than our rate of return on traditional oil and gas operations. Generally, finding and development costs are lower and operating costs are higher than traditional oil and gas operations. We have been developing tertiary oil properties for over 15 years, and the financial impact of such operations is reflected in our historical financial statements. The summary below highlights our observations regarding how tertiary operations have impacted our financial statements.

Finding and Development Costs. We currently expect finding and development costs (including future development and abandonment costs but excluding CO_2 pipeline infrastructure capital expenditures) over the life of each field to be lower than the industry average costs for other oil properties. See the definition of finding and development costs in the *Glossary and Selected Abbreviations*.

Timing of Capital Costs. There is a significant delay between the initial capital expenditures on tertiary oil fields and the resulting production increases. We must build facilities, and often a CO_2 pipeline to the field, before CO_2 flooding can commence, and it usually takes six to twelve months before the field responds to the injection of CO_2 (i.e., oil production commences). Further, we may spend significant amounts of capital before we can recognize any proved reserves from fields we flood and, even after a field has proved reserves, significant amounts of additional capital will usually be required to fully develop the field.

Recognition of Proved Reserves. In order to recognize proved tertiary oil reserves, we must either demonstrate production resulting from the tertiary process or the field must be analogous to an existing tertiary flood. The magnitude of proved reserves that we can book in any given year will depend on our progress with new floods, the timing of the production response from new floods and the performance of our existing floods. Typically, a high percentage of the potential reserves for a tertiary field are recognized when a production response is initially observed, and generally only modest increases are made thereafter.

Production Rates. The production growth rate at a tertiary flood can vary from quarter to quarter, as a tertiary field's production may increase rapidly when wells respond to the CO_2, plateau temporarily, and then resume growth as additional areas of the field are developed. During a tertiary flood life cycle, facility capacity is increased from time to time, which occasionally requires temporary shutdowns during installation, thereby causing temporary declines in production. We also find it difficult to precisely predict when any given well will respond to the injected CO_2, as the CO_2 seldom travels through the rock consistently due to heterogeneity in the oil-bearing formations. We find all of these fluctuations to be normal, and generally expect oil production at a tertiary field to increase over time until the field is fully developed, albeit sometimes in inconsistent patterns.

Operating Costs. Tertiary projects may be more expensive to operate than traditional industry operations because of the cost of injecting and recycling the CO_2 (primarily due to the cost of the CO_2 and the significant energy requirements to re-compress the CO_2 back into a near-liquid state for re-injection purposes). The costs of our CO_2 and the electricity required to recycle and inject this CO_2 comprise over half of our typical tertiary operating expenses. Since these costs vary along with commodity and commercial electricity prices, they are highly variable and will increase in a high-commodity-price environment and decrease in a low-price environment. Most of our CO_2 operating costs are allocated to our tertiary oil fields and recorded as lease operating expenses (following the commencement of tertiary oil production) at the time the CO_2 is injected. These costs have historically represented approximately 20% to 25% of the total operating costs for our tertiary operations. Since we expense all of the operating costs to produce and inject our CO_2 (following the commencement of tertiary oil production), operating costs per barrel for a new flood will be higher at the inception of CO_2 injection projects because of minimal related oil production at that time.

RESULTS OF OPERATIONS

Operating Results Table

Certain of our operating results and statistics for each of the last three years are included in the following table.

In thousands, except per share and unit data	Year Ended December 31, 2014	2013	2012
Operating results			
Net income	$ 635,491	$ 409,597	$ 525,360
Net income per common share – basic	1.82	1.12	1.36
Net income per common share – diluted	1.81	1.11	1.35
Dividends declared per common share	0.25	—	—
Net cash provided by operating activities	1,222,825	1,361,195	1,410,891
Average daily production volumes			
Bbls/d	70,606	66,286	66,837
Mcf/d	22,955	23,742	29,109
BOE/d	74,432	70,243	71,689
Operating revenues			
Oil sales	$ 2,338,367	$ 2,435,625	$ 2,377,337
Natural gas sales	34,106	30,609	32,530
Total oil and natural gas sales	$ 2,372,473	$ 2,466,234	$ 2,409,867
Commodity derivative contracts (1)			
Receipt (payment) on settlements of commodity derivatives	$ 1,421	$ (662)	$ 17,880
Noncash fair value adjustments on commodity derivatives (2)	553,834	(40,362)	(13,046)
Commodity derivatives income (expense)	$ 555,255	$ (41,024)	$ 4,834
Unit prices – excluding impact of derivative settlements			
Oil price per Bbl	$ 90.74	$ 100.67	$ 97.18
Natural gas price per Mcf	4.07	3.53	3.05
Unit prices – including impact of derivative settlements (1)			
Oil price per Bbl	$ 90.82	$ 100.64	$ 96.77
Natural gas price per Mcf	3.99	3.53	5.67
Oil and natural gas operating expenses			
Lease operating expenses (3)	$ 647,559	$ 730,574	$ 532,359
Marketing expenses, net of third-party purchases, and plant operating expenses	47,965	37,754	41,936
Production and ad valorem taxes	155,495	162,791	149,919
Oil and natural gas operating revenues and expenses per BOE			
Oil and natural gas revenues	$ 87.33	$ 96.19	$ 91.85
Lease operating expenses (3)	23.84	28.50	20.29
Marketing expenses, net of third-party purchases, and plant operating expenses	1.76	1.47	1.60
Production and ad valorem taxes	5.72	6.35	5.71
CO_2 sources and helium – revenues and expenses			
CO_2 and helium sales and transportation fees	$ 44,643	$ 27,950	$ 26,453
CO_2 and helium discovery and operating expenses (4)	(25,222)	(16,916)	(14,694)
CO_2 and helium revenue and expenses, net	$ 19,421	$ 11,034	$ 11,759

(1) See also *Commodity Derivative Contracts* below and *Market Risk Management* for information concerning our commodity derivative transactions.

(2) Noncash fair value adjustments on commodity derivatives is a non-GAAP measure and is different from "Commodity derivatives expense (income)" in the Consolidated Statements of Operations in that the noncash fair value adjustments on commodity derivatives represent only the net change between periods of the fair market values of commodity derivative positions, and exclude the impact of settlements on commodity derivatives during the period, which were receipts (payments) on settlements of $1.4 million, ($0.7 million) and $17.9 million for the years ended December 31, 2014, 2013 and 2012, respectively. We believe that noncash fair value adjustments on commodity derivatives is a useful supplemental disclosure to "Commodity derivatives expense (income)" in order to differentiate noncash fair market value adjustments from settlements on commodity derivatives during the period. This supplemental disclosure is widely used within the industry and by securities analysts, banks and credit rating agencies in calculating EBITDA and in adjusting net income to present those measures on a comparative basis across companies, as well as to assess compliance with certain debt covenants. Noncash fair value adjustments on commodity derivatives is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for "Commodity derivatives expense (income)" in the Consolidated Statements of Operations. See also the *Glossary and Selected Abbreviations* for the definition of noncash fair value adjustments on commodity derivatives.

(3) If lease operating expenses and related insurance recoveries recorded to remediate an area of Delhi Field were excluded, lease operating expenses would have totaled $654.7 million and $616.6 million for the years ended December 31, 2014 and 2013, respectively, and lease operating expenses per BOE would have averaged $24.10 and $24.05 for the years ended December 31, 2014 and 2013, respectively (see *Capital Resources and Liquidity – Insurance Recoveries to Cover Costs of 2013 Delhi Field Release* above).

(4) Includes $0.8 million and $9.5 million of exploratory costs incurred for the years ended December 31, 2013 and 2012, respectively. We incurred no exploratory costs for the year ended December 31, 2014.

Production

Average daily production by area for 2014, 2013 and 2012, and for each of the quarters of 2014, is shown below:

	Average Daily Production (BOE/d)						
	2014 Quarters				Year Ended December 31,		
Operating Area	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	2014	2013	2012
Tertiary oil production							
Gulf Coast region							
Mature properties							
Brookhaven	1,877	1,818	1,767	1,579	1,759	2,223	2,692
Eucutta	2,181	2,150	2,224	1,995	2,137	2,514	2,868
Mallalieu	1,837	1,839	1,869	1,653	1,799	2,050	2,338
Other mature properties (1)	6,283	6,156	6,189	5,864	6,122	7,016	7,707
Total mature properties	12,178	11,963	12,049	11,091	11,817	13,803	15,605
Delhi (2)	4,708	4,543	4,377	3,743	4,340	5,149	4,315
Hastings	4,618	4,759	4,917	4,811	4,777	3,984	2,188
Heidelberg	5,325	5,609	5,721	6,164	5,707	4,466	3,763
Oyster Bayou	4,055	4,415	4,605	5,638	4,683	2,968	1,388
Tinsley	8,430	8,518	8,310	8,767	8,507	8,051	7,947
Total Gulf Coast region	39,314	39,807	39,979	40,214	39,831	38,421	35,206
Rocky Mountain region							
Bell Creek	578	1,090	1,648	1,659	1,248	56	—
Total Rocky Mountain region	578	1,090	1,648	1,659	1,248	56	—
Total tertiary oil production	39,892	40,897	41,627	41,873	41,079	38,477	35,206
Non-tertiary oil and gas production							
Gulf Coast region							
Mississippi	2,513	2,319	2,346	2,099	2,318	2,695	3,930
Texas	6,444	6,508	5,537	6,677	6,290	6,540	4,737
Other	1,031	1,049	1,083	1,082	1,061	1,097	1,235
Total Gulf Coast region	9,988	9,876	8,966	9,858	9,669	10,332	9,902
Rocky Mountain region							
Cedar Creek Anticline (3)	19,007	19,155	18,623	18,553	18,834	16,572	8,503
Other	4,831	5,392	4,594	4,591	4,850	4,862	3,231
Total Rocky Mountain region	23,838	24,547	23,217	23,144	23,684	21,434	11,734
Total non-tertiary production	33,826	34,423	32,183	33,002	33,353	31,766	21,636
Total continuing production	73,718	75,320	73,810	74,875	74,432	70,243	56,842
Properties disposed							
Bakken area assets (4)	—	—	—	—	—	—	14,395
2012 non-core assets divestitures (5)	—	—	—	—	—	—	452
Total production	73,718	75,320	73,810	74,875	74,432	70,243	71,689

(1) Other mature properties include Cranfield, Little Creek, Lockhart Crossing, Martinville, McComb and Soso fields.

(2) The average daily Delhi Field production amounts for the fourth quarter of 2014 reflect the reversionary assignment of approximately 25% of our interest in that field effective November 1, 2014. The effectiveness, timing, and scope of the reversionary assignment are subject to ongoing litigation, the ultimate outcome of which cannot be predicted.

(3) Beginning March 27, 2013, amounts include production from our purchase of additional interests in the CCA on that date.

(4) Includes production from certain Bakken area assets sold in the fourth quarter of 2012.

(5) Includes production from certain non-core Gulf Coast assets sold in late February 2012 and certain non-operated assets in the Greater Aneth Field in the Paradox Basin of Utah sold in April 2012.

Total Production

Total production during 2014 averaged 74,432 BOE/d, an increase of 4,189 BOE/d (6%) compared to 2013 levels, due primarily to a 2,602 Bbl/d (7%) production increase from our tertiary oil fields in 2014 and our receiving only nine months of production in 2013 from the purchase of additional interests in CCA in late March 2013, partially offset by a decrease of 663 BOE/d in our Gulf Coast non-tertiary production.

Total production during 2013 averaged 70,243 BOE/d, a decrease of 1,446 BOE/d (2%) compared to 2012 levels, primarily due to the inclusion in 2012 of 11 months of production from our Bakken area assets (which were sold late in the fourth quarter of 2012), compared to the inclusion of only nine months of additional CCA production in our 2013 results. This decline in production due to timing of transactions was partially offset by a 9% increase in tertiary production in 2013.

Our production during 2014 was 95% oil compared to 94% for 2013 and 93% for 2012.

Tertiary Production

Oil production from our tertiary operations increased to record levels during 2014, averaging 41,079 Bbls/d, a 7% increase over our 2013 tertiary production level of 38,477 Bbls/d, primarily due to production growth in response to continued field development and expansion of facilities in our tertiary floods at Hastings, Heidelberg, Oyster Bayou, and Tinsley fields in our Gulf Coast region, and Bell Creek Field in our Rocky Mountain region. Partially offsetting these 2014 production gains were production declines in our mature tertiary fields, as well as declines at Delhi Field due to the mid-2013 incident (see Note 11*, Commitments and Contingencies,* to the Consolidated Financial Statements for further discussion), which slowed our development activities at Delhi Field, and the November 1, 2014, reduction in our Delhi Field interest due to the contractual reversionary assignment of approximately 25% of our interest to the seller of the field, the effectiveness, timing, and scope of which are subject to ongoing litigation.

Our fourth quarter of 2014 tertiary oil production, compared to that in the third quarter of 2014, increased slightly despite the Delhi reversionary interest assignment that reduced our fourth quarter production by approximately 750 Bbls/d. We had significant increases in fourth quarter tertiary oil production at Oyster Bayou Field (1,033 Bbls/d), Tinsley Field (457 Bbls/d) and Heidelberg Field (443 Bbls/d), which more than offset the Delhi decrease and the approximate 960 Bbl/d decrease in our mature tertiary floods. Although we have experienced appreciable production increases at Oyster Bayou and Tinsley fields during both the full year and fourth quarter of 2014, we anticipate that (1) our production at Tinsley Field has peaked and will likely start to decline sometime during 2015, and (2) our production at Oyster Bayou Field will begin to plateau in 2015. Also, with our significant reduction in capital spending in 2015, we are expecting overall production for 2015 to be relatively flat with, or slightly lower than, 2014 levels, and unless we are able to increase our capital spending in the near future, it is likely that our production levels will start to decline more significantly beginning in 2016.

Oil production from our tertiary operations during 2013 averaged 38,477 Bbls/d, a 9% increase over our 2012 tertiary production level of 35,206 Bbls/d, primarily due to production growth in 2013 in response to continued field development and expansion of facilities in our tertiary floods at Delhi, Hastings, Heidelberg, and Oyster Bayou fields. Offsetting these 2013 production gains were production declines in our more mature tertiary fields.

Non-Tertiary Production

Production from our non-tertiary operations averaged 33,353 BOE/d during 2014, an increase of 1,587 BOE/d (5%) compared to 2013 levels. The non-tertiary production increase was primarily due to the additional three months of production in 2014 from the purchase of additional interests in the CCA in late March 2013. When comparing 2013 to 2012, continuing production from our non-tertiary operations, which excludes production from our Bakken and other non-core assets divested during 2012, increased to an average of 31,766 BOE/d, an increase of 10,130 BOE/d (47%) from 2012 continuing production levels. The non-tertiary continuing production increase was primarily due to production from newly acquired fields, specifically the additional interests in CCA acquired in March 2013, Webster and Hartzog Draw fields acquired in the Bakken Exchange Transaction in late 2012, and Thompson Field acquired in June 2012. With the exception of the impact of the production added from fields acquired during 2012 and 2013 and anticipated increases in production at CCA due to infill drilling and optimization work, production from our other non-tertiary properties is generally on decline. In addition, the decline is pronounced in some instances when non-tertiary wells are shut in as part of an initiation or expansion of our tertiary floods in a field or an area of a field.

Oil and Natural Gas Revenues

Oil and natural gas revenues decreased 4% between 2013 and 2014 and increased 2% between 2012 and 2013. The changes in our oil and natural gas revenues are due to changes in production quantities and commodity prices (excluding any impact of our commodity derivative contracts) as reflected in the following table:

	Year Ended December 31, 2014 vs. 2013		Year Ended December 31, 2013 vs. 2012	
In thousands	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues
Change in oil and natural gas revenues due to:				
Increase (decrease) in production	$ 147,093	6%	$ (55,065)	(2)%
Increase (decrease) in commodity prices	(240,854)	(10)%	111,432	4%
Total increase (decrease) in oil and natural gas revenues	$ (93,761)	(4)%	$ 56,367	2%

Excluding any impact of our commodity derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during 2014, 2013 and 2012:

	Year Ended December 31,		
	2014	2013	2012
Net realized prices			
Oil price per Bbl	$90.74	$100.67	$97.18
Natural gas price per Mcf	4.07	3.53	3.05
Price per BOE	87.33	96.19	91.85
NYMEX differentials			
Oil per Bbl	$ (2.21)	$ 2.62	$ 2.99
Natural gas per Mcf	(0.20)	(0.19)	0.23

As reflected in the table above, our average net realized oil price, excluding the impact of commodity derivative contracts, decreased 10% during 2014 compared to the average price received during 2013. Company-wide average oil price differentials were $2.21 per Bbl below NYMEX in 2014, compared to an average differential of $2.62 per Bbl above NYMEX in 2013 (a $4.83 per Bbl decrease) and $2.99 per Bbl above NYMEX in 2012. During 2014, we sold approximately 43% of our crude oil at prices based on the LLS index price, approximately 23% at prices partially tied to the LLS index price, and the balance at prices based on various other indexes tied to NYMEX prices, primarily in the Rocky Mountain region. The net differential we received was primarily impacted by positive differentials in the Gulf Coast region, offset by unfavorable differentials in the Rocky Mountain region, each of which is discussed in further detail below.

We received favorable NYMEX differentials in the Gulf Coast region during 2014, 2013 and 2012, primarily due to the favorable differential for crude oil sold under LLS index prices. During 2014, the quarterly average LLS-to-NYMEX differential (on a trade-month basis) decreased from a positive $6.06 per Bbl in the first quarter of 2014 to a positive $3.16 per Bbl in the fourth quarter of 2014, with the most recent quarter being more representative of longer-term historical differentials. The LLS-to-NYMEX differential (on a trade-month basis) averaged $11.10 per Bbl and $16.44 per Bbl in 2013 and 2012, respectively.

NYMEX oil differentials in the Rocky Mountain region averaged $10.19 per Bbl below NYMEX during 2014 compared to an average differential of $8.10 per Bbl below NYMEX in 2013 and $11.86 per Bbl below NYMEX in 2012. Differentials in the Rocky Mountain region can move significantly over short periods of time due to refinery and transportation issues, but generally have become more stable over the last couple of years as infrastructure and takeaway capacity has improved in the area. The change in the differential between 2012 and 2013 was largely impacted by the sale of our Bakken area assets in the fourth quarter of 2012, since oil from the Bakken area assets generally sold at a higher discount to NYMEX than the CCA production acquired in early 2013.

Prices received in a regional market fluctuate frequently and can differ from NYMEX pricing due to a variety of reasons, including supply and/or demand factors and location differentials. Although the LLS and Rocky Mountain differentials improved somewhat in 2014 compared to the levels in the fourth quarter of 2013, we do not expect the LLS-to-NYMEX differential in the Gulf Coast region to return to the significantly elevated levels we experienced during most of 2013 and 2012.

Our natural gas NYMEX differentials are generally caused by movement in the NYMEX natural gas prices during the month, as most of our natural gas is sold on an index price that is set near the first of each month. While the percentage change in NYMEX natural gas differentials can be quite large, the absolute impact of these changes on our results has historically been minor, as natural gas sales represented only approximately 1% of our oil and natural gas revenues during 2014.

Commodity Derivative Contracts

From time to time, we enter into oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production. These contracts have historically consisted of price floors, collars, three-way collars, fixed-price swaps, and fixed-price swaps enhanced with a sold put. The following table summarizes the impact our oil and natural gas derivative contracts had on our operating results for 2014, 2013 and 2012:

	Noncash Fair Value Gain/(Loss) [1]			Receipt/(Payment) on Settlements		
In thousands	2014	2013	2012	2014	2013	2012
Crude oil derivative contracts						
First quarter	$ (48,854)	$(11,929)	$(42,445)	$ (26,559)	$ —	$(8,230)
Second quarter	(124,865)	45,501	140,923	(49,895)	—	(709)
Third quarter	276,240	(79,784)	(60,726)	(25,016)	(662)	(641)
Fourth quarter	448,365	5,854	(26,848)	103,555	—	(411)
Full Year	$ 550,886	$(40,358)	$ 10,904	$ 2,085	$(662)	$(9,991)
Natural gas derivative contracts						
First quarter	$ (646)	$ —	$ (1,640)	$ (610)	$ —	$ 7,040
Second quarter	266	—	(9,096)	(277)	—	7,991
Third quarter	939	—	(7,174)	102	—	6,910
Fourth quarter	2,389	(4)	(6,040)	121	—	5,930
Full Year	$ 2,948	$ (4)	$(23,950)	$ (664)	$ —	$27,871
Total commodity derivative contracts						
First quarter	$ (49,500)	$(11,929)	$(44,085)	$ (27,169)	$ —	$(1,190)
Second quarter	(124,599)	45,501	131,827	(50,172)	—	7,282
Third quarter	277,179	(79,784)	(67,900)	(24,914)	(662)	6,269
Fourth quarter	450,754	5,850	(32,888)	103,676	—	5,519
Full Year	$ 553,834	$(40,362)	$(13,046)	$ 1,421	$(662)	$17,880

(1) Noncash fair value adjustments on commodity derivatives is a non-GAAP measure. See *Operating Results Table* above for a discussion of the reconciliation between noncash fair value adjustments on commodity derivatives to "Commodity derivatives expense (income)" in the Consolidated Financial Statements. See also the *Glossary and Selected Abbreviations* for the definition of noncash fair value adjustments on commodity derivatives.

During 2014, in order to provide greater certainty to the range of our anticipated operating cash flows as we transitioned to a dividend-paying company, we utilized more fixed-price swaps than we have historically. Prior to 2014, most of our derivative contracts were collars that had a floor and ceiling price that provided price protection at a lower level, but also a wider range of variability in operating cash flows than if we had used fixed-price swap contracts. For 2015, we have entered into a combination of enhanced swaps, collars, and three-way collars covering a total of 58,000 Bbls/d for the first three quarters of 2015 and 38,000 Bbls/d for the fourth quarter of 2015. Roughly half of these 2015 derivative contracts are collars and three-way collars, so the variability in potential cash flows from these types of hedges exposes us to more downside price risk than our 2014 fixed-price swaps. These 2015 collars and three-way collars, which include both NYMEX and LLS hedges, have a weighted average floor of approximately $82 per Bbl (approximately $81 per Bbl and $86 per Bbl for NYMEX and LLS hedges, respectively) and a weighted average ceiling price of approximately $97 per Bbl (approximately $96 per Bbl and $101 per Bbl for NYMEX and LLS hedges, respectively). Our three-way collars and enhanced swaps all include sold puts that have a weighted average price of approximately $67 per Bbl. The sold puts for our three-way collars and enhanced swaps limit the benefit that our hedges provide us to the extent that oil prices fall below the price of our sold puts. Likewise, our 2016 commodity derivative contracts all include sold puts, similarly limiting our potential cash flows from these instruments to the extent that oil prices are below the prices of our sold puts.

Changes in commodity prices and the expiration of contracts cause fluctuations in the estimated fair value of our oil and natural gas derivative contracts. Because we do not utilize hedge accounting for our commodity derivative contracts, the period-to-period changes in the fair value of these contracts, as outlined above, are recognized in our statements of operations. The details of our outstanding commodity derivative contracts at December 31, 2014, are included in Note 9, *Commodity Derivative Contracts,* to the Consolidated Financial Statements.

Production Expenses

Lease operating expense

In thousands, except per BOE data	Year Ended December 31, 2014	2013	2012
Lease operating expense			
Tertiary – excluding Delhi Field remediation	$385,080	$358,281	$307,686
Tertiary – Delhi Field remediation	(7,134)	114,000	—
Non-tertiary	269,613	258,293	224,673
Total lease operating expense	$647,559	$730,574	$532,359
Lease operating expense per BOE			
Tertiary – excluding Delhi Field remediation	$ 25.68	$ 25.51	$ 23.88
Tertiary – Delhi Field remediation	(0.47)	8.12	—
Non-tertiary	22.15	22.28	16.83
Total lease operating expense per BOE (1)	23.84	28.50	20.29

(1) Excluding estimated costs and related insurance recoveries recorded to remediate an area of Delhi Field, total operating expense per BOE averaged $24.10 and $24.05 during the years ended December 31, 2014 and 2013, respectively. See *Capital Resources and Liquidity – Insurance Recoveries to Cover Costs of 2013 Delhi Field Release* and Note 11, *Commitments and Contingencies,* to the Consolidated Financial Statements for further discussion of this matter.

Total lease operating expenses decreased $83.0 million (11%) on an absolute-dollar basis or $4.66 (16%) on a per-BOE basis during 2014 compared to 2013 levels, primarily due to Delhi remediation charges of $114.0 million during 2013, compared to a net reduction of lease operating expenses of $7.1 million in 2014 (see *Capital Resources and Liquidity – Insurance Recoveries to Cover Costs of 2013 Delhi Field Release* and Note 11, *Commitments and Contingencies,* to the Consolidated Financial Statements for further discussion of the Delhi remediation costs and insurance reimbursements). Excluding Delhi Field remediation costs and insurance reimbursements, total lease operating expenses increased $38.1 million (6%) on an absolute-dollar basis or $0.05 on a per-BOE basis during 2014 compared to 2013 levels, due primarily to (1) costs associated with expansion of tertiary floods, including a full year of lease operating expense at Bell Creek Field which increased our operating expenses by approximately $19 million from 2013 levels, (2) a full year of operating expenses associated with our acquisition of additional interests in CCA in late March 2013 as compared to only approximately nine months of expenses associated with our additional interests in CCA in 2013, which increased operating expense by approximately $10 million, (3) higher power costs in 2014 due in part to higher natural gas prices, and (4) the impact of a large unplanned well workover at Riley Ridge, which increased operating expenses by approximately $12 million in 2014. Offsetting some of these increases were savings associated with our more efficient utilization of CO_2, which allowed us to reduce injections at some of our fields and lower workover costs across many of our fields, which was a primary focus for us in 2014. On a quarterly basis, excluding Delhi remediation costs and insurance reimbursements and unplanned Riley Ridge well workovers, our lease operating expense per BOE decreased each sequential quarter in 2014 and decreased a total of 14% between the fourth quarter of 2013 and the fourth quarter of 2014, due largely to lower workover costs. Lease operating expense increased $198.2 million (37%) on an absolute-dollar basis or $8.21 (40%) on a per-BOE basis during 2013 compared to 2012 levels, primarily due to the Delhi remediation charges of $114.0 million during 2013. Excluding these remediation charges, lease operating expenses increased $84.2 million (16%) or $3.76 per BOE during 2013 compared to 2012 levels, due primarily to increased expenses resulting from the expansion of our tertiary floods, including our tertiary flood at Bell Creek Field; increases in the cost and utilization of CO_2 between the comparative periods; and higher lease operating expenses at the fields we acquired in the Bakken Exchange Transaction relative to the Bakken assets we sold late in the fourth quarter of 2012.

Tertiary lease operating expenses decreased $94.3 million (20%) on an absolute-dollar basis or $8.42 (25%) on a per-Bbl basis during 2014 compared to 2013 levels, primarily due to the Delhi remediation charges noted above. Excluding Delhi remediation costs and insurance reimbursements, tertiary lease operating expenses increased $26.8 million (7%) on an absolute-dollar basis and $0.17 on a per-Bbl basis during 2014 compared to 2013 levels, due primarily to additional costs associated with our newest tertiary flood at Bell Creek Field which had initial production and operating expense in the third quarter of 2013, as well as its production being low relative to operating costs because production is still ramping up, resulting in high per-barrel operating costs, which is typical when we startup a new tertiary flood. The increase between periods is further impacted by higher power costs due to higher rates and usage during 2014. Although there was an overall increase in the cost of CO_2 due to our newest tertiary flood at Bell Creek Field in the Rocky Mountain region, CO_2 utilization in the Gulf Coast region decreased between 2013 and 2014 as a result of improved efficiency and utilization of CO_2 for those fields. During 2013, tertiary lease operating expense, excluding Delhi remediation costs and insurance reimbursements, increased $50.6 million (16%) on an absolute-dollar basis or $1.63 on a per-Bbl basis compared to 2012, primarily as a result of the expansion of our tertiary floods and increased CO_2 expenses due to increases in the cost of CO_2 and an increase in CO_2 volumes injected into tertiary floods between years. For any specific field, we expect our tertiary lease operating expense per barrel to be high initially, as we experienced in 2013 and 2014 with our Bell Creek flood, and then decrease as production increases, ultimately leveling off until production begins to decline in the later life of the field, when operating expense per barrel will again increase. One of our most substantial costs in our tertiary operations is our cost for fuel and utilities, averaging $7.46 per Bbl in 2014, $6.64 per Bbl in 2013 and $6.51 per Bbl in 2012, which has increased on a per-barrel basis due to the higher cost of these items and the continued expansion of our tertiary floods.

Currently, our CO_2 expense comprises approximately one-fourth of our typical tertiary lease operating expenses, and for the CO_2 reserves we already own, consists of our CO_2 production expenses, and for the CO_2 reserves we do not own, consists of our purchase of CO_2 from royalty and working interest owners and industrial sources. During the year ended December 31, 2014, approximately 65% of the CO_2 utilized in our CO_2 floods consisted of CO_2 owned and produced by us, and we purchased the remaining portion from third-party owners (primarily royalty owners). The price we pay others for CO_2 varies by source and is generally indexed to oil prices. When combining the production cost of the CO_2 we own with what we pay third parties for CO_2, our average cost of CO_2 during 2014 was approximately $0.37 per Mcf, including taxes paid on CO_2 production but excluding depletion and depreciation of capital. This rate during 2014 was higher than the $0.36 per Mcf comparable measure during 2013 and $0.26 per Mcf spent during 2012, primarily due to fluctuations in pricing of our Rocky Mountain region CO_2 and increased volumes purchased from industrial sources during 2014. Including the cost of depreciation and amortization of capital expended at our CO_2 source fields and industrial sources, but excluding depreciation of our CO_2 pipelines, our cost of CO_2 was $0.48 per Mcf in 2014, $0.44 per Mcf in 2013 and $0.33 per Mcf in 2012.

Non-tertiary lease operating expenses increased $11.3 million (4%) on an absolute-dollar basis during 2014 compared to 2013 levels, primarily due to workover costs at Riley Ridge of approximately $12 million, as well as our late-March 2013 purchase of additional interests in CCA, which caused an increase in costs, but which properties generally have a lower operating cost on a per-BOE basis than our other non-tertiary properties. Non-tertiary lease operating expenses increased 15% on an absolute-dollar basis from 2012 to 2013, as declines resulting from the sale of our Bakken area assets were more than offset by increases in newly acquired fields, including Thompson field acquired in the second quarter of 2012, Webster and Hartzog Draw fields acquired in the Bakken Exchange Transaction in late 2012, and additional interests in CCA acquired in the first quarter of 2013. On a per-BOE basis, non-tertiary lease operating expense increased 32% from 2012 to 2013 due to increases in newly acquired fields, which have a higher per-BOE operating cost than the properties disposed in the Bakken Exchange Transaction.

Marketing and plant operating expenses

Marketing and plant operating expenses primarily consist of amounts incurred related to the marketing, processing, and transportation of oil and natural gas production, as well as expenses related to our Riley Ridge gas processing facility. Marketing and plant operating expenses increased $15.1 million between 2013 and 2014 and decreased $3.6 million between 2012 and 2013. The increase during 2014 is primarily related to the Riley Ridge gas processing facility, which was placed into service in the fourth quarter of 2013, slightly offset by other decreases.

Taxes other than income

Taxes other than income includes ad valorem, production and franchise taxes. Taxes other than income decreased $6.5 million between 2013 and 2014 and increased $16.2 million between 2012 and 2013. The levels of taxes other than income during most periods are generally aligned with fluctuations in oil and natural gas revenues. The decrease during 2014 is also impacted by cumulative reductions in severance taxes during 2014 at Hastings Field ($7.5 million) and Oyster Bayou Field ($7.4 million) for state-approved enhanced oil recovery project exemptions, which will also reduce severance taxes for those fields for approximately the next seven years, but to a much lesser degree on an annual basis, as these state-approved exemptions were carried back to certain prior years, with the full impact recorded in 2014. The changes are further impacted by the change in the mix of properties subject to production and ad valorem taxes as a result of the Bakken Exchange Transaction in late 2012 and the CCA acquisition in March 2013.

General and Administrative Expenses ("G&A")

	Year Ended December 31,		
In thousands, except per BOE data and employees	2014	2013	2012
Gross cash compensation and administrative costs	$ 352,651	$ 324,580	$ 296,696
Gross stock-based compensation	39,532	42,091	37,897
Operator labor and overhead recovery charges	(171,661)	(166,012)	(141,358)
Capitalized exploration and development costs	(62,179)	(55,448)	(49,216)
Net G&A expense	$ 158,343	$ 145,211	$ 144,019
G&A per BOE			
Net administrative costs	$ 4.81	$ 4.47	$ 4.48
Net stock-based compensation	1.02	1.19	1.01
Net G&A expense	$ 5.83	$ 5.66	$ 5.49
Employees as of December 31	1,523	1,501	1,432

Gross cash compensation and administrative costs on an absolute-dollar basis increased $28.1 million (9%) between 2013 and 2014 and $27.9 million (9%) between 2012 and 2013. The increase in both comparative periods is due primarily to higher compensation-related costs from increases in headcount and wage increases we consider necessary to remain competitive in our industry, insurance, and professional services. The increase during 2014 was further impacted by the 2013 period including a $1.9 million insurance reimbursement.

Net G&A expense on a per-BOE basis increased 3% between 2013 and 2014 and 3% between 2012 and 2013. The increase between both comparative periods was primarily due to higher compensation-related costs, partially offset by an increase in operator labor and overhead recovery charges and capitalized exploration and development costs. The 2014 period was further impacted by an increase in production in 2014 and the 2013 period including a $1.9 million insurance reimbursement.

Gross stock-based compensation costs decreased in 2014 compared to 2013, primarily due to a shift in the mix of long-term incentive compensation for employees. Gross stock-based compensation increased in 2013 compared to 2012 due to the increased number of employees during 2013 compared to 2012. Stock-based compensation, net of amounts capitalized or reclassified to field operations, was $27.8 million, $30.4 million and $26.5 million during the years ended December 31, 2014, 2013 and 2012, respectively.

Our well operating agreements allow us, when we are the operator, to charge a well with a specified overhead rate during the drilling phase and also to charge a monthly fixed overhead rate for each producing well. In addition, salaries associated with field personnel are initially recorded as gross cash compensation and administrative costs and subsequently reclassified to lease operating expenses or capitalized to field development costs to the extent those individuals are dedicated to oil and natural gas production, exploration, and development activities. As a result of additional operated wells, increased compensation expense and an increase in the COPAS overhead rate, the amount we recovered as operator labor and overhead recovery charges increased 3% between 2013 and 2014, and 17% between 2012 and 2013. Capitalized exploration and development costs also increased between the periods, primarily due to increased compensation costs subject to capitalization.

Interest and Financing Expenses

	Year Ended December 31,		
In thousands, except per BOE data and interest rates	2014	2013	2012
Cash interest expense	$ 193,729	$ 205,938	$ 216,205
Noncash interest expense	13,476	14,024	14,808
Less: Capitalized interest	(24,202)	(79,253)	(77,432)
Interest expense, net	$ 183,003	$ 140,709	$ 153,581
Interest expense, net per BOE	$ 6.74	$ 5.49	$ 5.85
Average debt outstanding	$3,597,646	$3,257,686	$2,935,485
Average interest rate (1)	5.4%	6.3%	7.4%

(1) Includes commitment fees but excludes debt issue costs and amortization of discount or premium.

As reflected in the table above, our average interest rate decreased each year in the period between 2012 and 2014. The lower rate in 2014 includes the impact of our April 2014 long-term debt refinancing, whereby we issued $1.25 billion of 5½% Notes to replace our $996.3 million of 8¼% Notes (see *Overview – April 2014 Debt Refinancing* above). The lower rates in 2014 and 2013 further reflect our refinancing in February 2013 of certain senior subordinated notes, which had interest rates of 9½% and 9¾%, with our 4⅝% Senior Subordinated Notes due 2023. In conjunction with these two refinancing transactions, we estimate that we will save approximately $60 million annually in cash interest expense on the principal amount of the refinanced notes; however, our savings will be partially offset by the incremental principal amount of the newly issued senior subordinated notes, some of which was used to repay lower rate bank debt. Although our cash interest costs are lower, as a result of completing major projects on which we had been previously capitalizing interest, specifically the Riley Ridge gas processing facility, Greencore Pipeline and the tertiary flood at Bell Creek Field, our capitalized interest during 2014 decreased significantly, contributing to an increase in net interest expense of $42.3 million (30%) between 2013 and 2014.

Interest expense, net decreased 8% between 2012 and 2013, largely due to a lower average interest rate and higher capitalized interest, partially offset by higher average debt outstanding.

Depletion, Depreciation, and Amortization ("DD&A")

In thousands, except per BOE data	Year Ended December 31, 2014	2013	2012
Depletion and depreciation of oil and natural gas properties	$460,726	$392,603	$420,094
Depletion and depreciation of CO_2 properties	30,986	27,783	23,843
Asset retirement obligations	8,870	8,450	7,228
Depreciation of pipelines, plants and other property and equipment	92,390	81,107	56,373
Total DD&A	$592,972	$509,943	$507,538
DD&A per BOE			
Oil and natural gas properties	$ 17.29	$ 15.64	$ 16.28
CO_2 properties, pipelines, plants and other property and equipment	4.54	4.25	3.06
Total DD&A expense per BOE	$ 21.83	$ 19.89	$ 19.34

We adjust our DD&A rate each quarter for significant changes in our estimates of oil and natural gas reserves and costs. In addition, under full cost accounting rules, the divestiture of oil and natural gas properties generally does not result in gain or loss recognition; instead, the proceeds of the disposition reduce the full cost pool. As such, our DD&A rate has changed significantly over time, and it may continue to change in the future. Depletion and depreciation of oil and natural gas properties and asset retirement obligations increased 17% on an absolute-dollar basis between 2013 and 2014. The increase on an absolute-dollar basis was due to both higher production volumes and a higher depletion rate per BOE compared to 2013. The DD&A rate per BOE for oil and natural gas properties increased 11% in 2014, compared to levels in 2013, primarily due to the recognition in late 2013 of proved reserves at Bell Creek Field and the related reclassification of costs from unevaluated to evaluated, and higher average forecasted future development costs throughout the year. Our depletion and depreciation rate of oil and natural gas properties increased to $18.17 per BOE for the fourth quarter of 2014, primarily the result of additional capitalized costs from current-year capital expenditures and lower year-end proved reserve volumes.

Depletion and depreciation of oil and natural gas properties and asset retirement obligations decreased 6% on an absolute-dollar basis and 4% on a per-BOE basis between 2012 and 2013. These decreases were primarily due to the Bakken Exchange Transaction in late 2012, which resulted in a decrease in capitalized costs relating to the sales proceeds credited to the full cost pool and a significant reduction in future development costs relating to the sold proved reserves, partially offset by the reduction in total proved reserves. This decrease in DD&A was partially offset by the impact of the CCA acquisition in the first quarter of 2013 and the movement of Bell Creek reserves from unevaluated to proved reserves during the fourth quarter of 2013.

Depletion and depreciation of our CO_2 properties, pipelines, plants and other property and equipment increased on an absolute-dollar and per-BOE basis during 2014 from 2013 levels, primarily due to the startup of the Riley Ridge gas processing facility in late 2013 and additional pipelines and CO_2 properties placed in service. Depletion and depreciation of our CO_2 properties, pipelines, plants and other property and equipment increased on an absolute-dollar and per-BOE basis in 2013 compared to 2012 due to an increase in CO_2 properties, pipelines and plants subject to depreciation as a result of continued development. The increase on a per-BOE basis in 2013 was further impacted by lower oil and natural gas production during 2013.

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. Under these rules, the full cost ceiling value is calculated using the average first-day of the month oil and natural gas price for each month during a 12-month rolling period ended as of each quarterly reporting period. We did not have a ceiling test write-down during 2014, 2013 or 2012. The representative oil and natural gas prices used to calculate the December 31, 2014, full cost ceiling value were $94.99 per Bbl for crude oil and $4.30 per MMBtu for natural gas, both of which were adjusted for market differentials by field. This prescribed methodology does not reflect significant crude oil price declines in late 2014 and early 2015, when oil prices dropped rapidly, declining to below $45 per Bbl in January 2015. If oil prices were to remain at or near these late 2014 and early 2015 levels in subsequent periods, we would likely begin recording write-downs due to the full cost pool ceiling test in either the first or second quarter of 2015, and also in subsequent quarterly periods if prices remain low, as the 12-month average price used in the full cost ceiling value would continue to decline during each rolling quarterly period in 2015. The possibility and amount of any future write-down or impairment is difficult to predict, and will depend, in part, upon oil and natural gas prices, the incremental proved reserves that may be added each period, revisions to previous reserve estimates and future capital expenditures and operating costs. See Item 1A, *Risk Factors, and Critical Accounting Policies and Estimates – Full Cost Method of Accounting, Depletion and Depreciation and Oil and Natural Gas Properties* for further discussion.

Income Taxes

In thousands, except per BOE amounts and tax rates	Year Ended December 31, 2014	2013	2012
Current income tax expense (benefit)	$ (42,907)	$ 10,257	$ 75,754
Deferred income tax expense	429,973	222,526	255,743
Total income tax expense	$ 387,066	$ 232,783	$ 331,497
Average income tax expense per BOE	$ 14.25	$ 9.08	$ 12.63
Effective tax rate	37.9%	36.2%	38.7%
Total net deferred tax liability	$2,776,569	$2,346,540	$2,124,296

Our income tax provisions for 2014 and 2013 were based on an estimated statutory rate of approximately 38%, while the 2012 tax provision was based on an estimated statutory rate of approximately 38.5%. The fluctuation in our statutory rate is significantly driven by a shift in the amount of revenues we earn in each state due to acquisitions and divestitures and other production changes. Our effective tax rate was consistent with our estimated statutory rates in 2014 and 2012, while our 2013 effective tax rate was lower than our statutory rate due to the revaluation of our deferred taxes as a result of the lower overall statutory rate compared to 2012, as well as the inclusion of differences between our 2012 tax provision and our 2012 filed tax returns.

We recorded current income tax benefits in 2014 in recognition of reinstated bonus depreciation becoming available in December 2014, along with an increase in certain tax preference items. We expect this benefit to be carried back to our filed tax returns in prior years. Current income tax expense during 2013 is primarily related to state income taxes. The higher level of current income tax expense during 2012 included $42 million of current taxes resulting from the taxable gain recognized in the Bakken Exchange Transaction that we were unable to defer through a like-kind exchange transaction.

As of December 31, 2014, we had an estimated $42.8 million of enhanced oil recovery credits to carry forward related to our tertiary operations and $34.8 million of alternative minimum tax credits that can be utilized to reduce our current income taxes during 2015 or future years. These enhanced oil recovery credits do not begin to expire until 2024. Since the ability to earn additional enhanced oil recovery credits is based upon the level of oil prices, we would not currently expect to earn additional enhanced oil recovery credits unless oil prices were to continue to deteriorate.

Per-BOE Data

The following table summarizes our cash flow, DD&A and results of operations on a per-BOE basis for the comparative periods. Each of the individual components is discussed above.

Per-BOE data	Year Ended December 31, 2014	2013	2012
Oil and natural gas revenues	$ 87.33	$ 96.19	$ 91.85
Receipt (payment) on settlements of commodity derivatives	0.05	(0.03)	0.68
Lease operating expenses – excluding Delhi Field remediation	(24.10)	(24.05)	(20.29)
Lease operating expenses – Delhi Field remediation	0.26	(4.45)	—
Production and ad valorem taxes	(5.72)	(6.35)	(5.71)
Marketing expenses, net of third-party purchases, and plant operating expenses	(1.76)	(1.47)	(1.60)
Production netback	56.06	59.84	64.93
CO_2 and helium sales, net of operating and exploration expenses	0.71	0.43	0.45
General and administrative expenses	(5.83)	(5.66)	(5.49)
Interest expense, net	(6.74)	(5.49)	(5.85)
Other	2.50	0.48	(1.44)
Changes in assets and liabilities relating to operations	(1.69)	3.49	1.17
Cash flow from operations	45.01	53.09	53.77
DD&A	(21.83)	(19.89)	(19.34)
Deferred income taxes	(15.83)	(8.68)	(9.75)
Loss on early extinguishment of debt	(4.19)	(1.74)	—
Noncash fair value adjustments on commodity derivatives	20.39	(1.57)	(0.50)
Impairment of assets	—	—	(0.67)
Other noncash items	(0.16)	(5.23)	(3.49)
Net income	$ 23.39	$ 15.98	$ 20.02

MARKET RISK MANAGEMENT

Debt

We finance some of our acquisitions and other expenditures with fixed and variable rate debt. These debt agreements expose us to market risk related to changes in interest rates. At December 31, 2014, we had $395.0 million in outstanding borrowings on our Bank Credit Facility. None of our existing debt has any triggers or covenants regarding our debt ratings with rating agencies, although under the NEJD financing lease, in the event of significant downgrades of our corporate credit rating by the rating agencies, certain credit enhancements can be required from us, and possibly other remedies made available under the lease. In addition, our credit rating can potentially reduce our drawn borrowing costs under our Bank Credit Facility during an "investment grade period," though we do not anticipate having the ability to make such an election in the foreseeable future. The fair value of our senior subordinated debt is based on quoted market prices. The following table presents the principal cash flows and fair values of our outstanding debt at December 31, 2014:

In thousands	2015	2017	2019	2021	2022	2023	Total	Fair Value
Variable rate debt								
Bank Credit Facility (weighted average interest rate of 1.9% at December 31, 2014)	$ —	$ —	$395,000	$ —	$ —	$ —	$ 395,000	$ 395,000
Fixed rate debt								
6 3/8% Senior Subordinated Notes due 2021	—	—	—	400,000	—	—	400,000	381,000
5 1/2% Senior Subordinated Notes due 2022	—	—	—	—	1,250,000	—	1,250,000	1,121,875
4 5/8% Senior Subordinated Notes due 2023	—	—	—	—	—	1,200,000	1,200,000	1,038,000
Other Subordinated Notes	485	2,250	—	—	—	—	2,735	2,735

See Note 5, *Long-Term Debt,* to the Consolidated Financial Statements for details regarding our long-term debt, including information regarding our April 2014 debt issuance (at a lower interest rate and for a longer term) and repurchase and redemption of our outstanding 8 1/4% Senior Subordinated Notes due 2020.

Oil and Natural Gas Derivative Contracts

From time to time, we enter into oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production. These contracts have historically consisted of price floors, collars, three-way collars, fixed-price swaps, and fixed-price swaps enhanced with a sold put. We do not hold or issue derivative financial instruments for trading purposes. The production that we hedge has varied from year to year depending on our levels of debt, financial strength, and expectation of future commodity prices. During 2014, in order to provide greater certainty to the range of our anticipated operating cash flows as we transitioned to a dividend-paying company, we utilized more fixed-price swaps than we had historically. For 2015, we have entered into a combination of enhanced swaps, collars, and three-way collars covering a total of 58,000 Bbls/d for the first three quarters of 2015 and 38,000 Bbls/d for the fourth quarter of 2015. Roughly half of these 2015 derivative contracts are collars and three-way collars, so the variability in potential cash flows from these types of hedges exposes us to more downside price risk than our 2014 fixed-price swaps. In addition, the sold puts that are part of our three-way collars and enhanced swaps limit the benefit that our hedges provide us to the extent that oil prices fall below the price of our sold puts. We anticipate that we may use more fixed-price swaps in the future or a combination of fixed-price swaps and collars as we look to provide more certainty around our cash flows in order to execute on our capital development plans, pay dividends and retain a healthy balance sheet. See Note 9, *Commodity Derivative Contracts,* to the Consolidated Financial Statements for additional information regarding our commodity derivative contracts.

All of the mark-to-market valuations used for our oil and natural gas derivatives are provided by external sources. We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures and diversification. All of our commodity derivative contracts are with parties that are lenders under our Bank Credit Facility (or affiliates of such lenders). We have included an estimate of nonperformance risk in the fair value measurement of our oil and natural gas derivative contracts, which we have measured for nonperformance risk based upon credit default swaps or credit spreads.

For accounting purposes, we do not apply hedge accounting to our oil and natural gas derivative contracts. This means that any changes in the fair value of these commodity derivative contracts will be charged to earnings on a quarterly basis instead of charging the effective portion to other comprehensive income and the ineffective portion to earnings.

At December 31, 2014, our commodity derivative contracts were recorded at their fair value, which was a net asset of approximately $506.5 million, a $553.8 million increase from the $47.3 million net liability recorded at December 31, 2013. This change is primarily related to the expiration of commodity derivative contracts during 2014, new commodity derivative contracts we entered into during 2014 for future periods, and the changes in oil and natural gas futures prices between December 31, 2013 and 2014.

Commodity Derivative Sensitivity Analysis

Based on NYMEX and LLS crude oil futures prices and natural gas futures prices as of December 31, 2014, and assuming both a 10% increase and decrease thereon, we would expect to receive payments on our crude oil and natural gas derivative contracts as shown in the following table:

	Receipt/(Payment)	
In thousands	Crude Oil Derivative Contracts	Natural Gas Derivative Contracts
Based on:		
NYMEX futures prices as of December 31, 2014	$626,879	$2,703
10% increase in prices	575,264	1,882
10% decrease in prices	674,812	3,527

Our commodity derivative contracts are used as an economic hedge of our exposure to commodity price risk associated with anticipated future production. As a result, changes in receipts or payments of our commodity derivative contracts due to changes in commodity prices as reflected in the above table would be mostly offset by a corresponding increase or decrease in the cash receipts on sales of our oil and natural gas production to which those commodity derivative contracts relate. In addition to the analysis performed in the table above, if NYMEX and LLS crude oil futures prices remained flat at $50 per Bbl during 2015 and 2016, we would expect to receive total payments on our crude oil and natural gas derivative contracts of approximately $560 million in 2015 and $121 million in 2016.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with generally accepted accounting principles requires that we select certain accounting policies and make certain estimates and judgments regarding the application of those policies. Our significant accounting policies are included in Note 1, *Significant Accounting Policies,* to the Consolidated Financial Statements. These policies, along with the underlying assumptions and judgments by our management in their application, have a significant impact on our consolidated financial statements. Following is a discussion of our most critical accounting estimates, judgments and uncertainties that are inherent in the preparation of our financial statements.

Full Cost Method of Accounting, Depletion and Depreciation and Oil and Natural Gas Properties

Businesses involved in the production of oil and natural gas are required to follow accounting rules that are unique to the oil and gas industry. We apply the full cost method of accounting for our oil and natural gas properties. Another acceptable method of accounting for oil and natural gas production activities is the successful efforts method of accounting. In general, the primary differences between the two methods are related to the capitalization of costs and the evaluation for asset impairment. Under the full cost method, all geological and geophysical costs, exploratory dry holes and delay rentals are capitalized to the full cost pool, whereas under the successful efforts method such costs are expensed as incurred. In the assessment of impairment of oil and natural gas properties, the successful efforts method follows the *Accounting for the Impairment or Disposal of Long-Lived Assets* topic of the FASC, under which the net book value of assets is measured for impairment against the undiscounted future cash flows using commodity prices consistent with management expectations. Under the full cost method, the full cost pool (net book value of oil and natural gas properties) is measured against future cash flows discounted at 10% using the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period ended as of each quarterly reporting period. The financial results for a given period could be substantially different depending on the method of accounting that an oil and gas entity applies. Further, we do not designate our oil and natural gas derivative contracts as hedge instruments for accounting purposes under the *Derivatives and Hedging* topic of the FASC (see below), and as a result, these contracts are not considered in the full cost ceiling test.

We make significant estimates at the end of each period related to accruals for oil and natural gas revenues, production, capitalized costs and operating expenses. We calculate these estimates with our best available data, which includes, among other things, production reports, price posting, information compiled from daily drilling reports and other internal tracking devices, and analysis of historical results and trends. While management is not aware of any required revisions to its estimates, there will likely be future adjustments resulting from such things as revisions in estimated oil and natural gas volumes, changes in ownership interests, payouts, joint venture audits, re-allocations by the purchasers or pipelines, or other corrections and adjustments common in the oil and gas industry, many of which will require retroactive application. These types of adjustments cannot be currently estimated or determined and will be recorded in the period during which the adjustment occurs.

Under full cost accounting, the estimated quantities of proved oil and natural gas reserves used to compute depletion and the related present value of estimated future net cash flows therefrom used to perform the full cost ceiling test have a significant impact on the underlying financial statements. The process of estimating oil and natural gas reserves is very complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continued reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that the reported reserve estimates represent the most accurate assessments possible, including the hiring of independent engineers to prepare reported estimates, the subjective decisions and variances in available data for various fields make these estimates generally less precise than other estimates included in our financial statement disclosures. Over the last four years, annual revisions to our reserve estimates have averaged approximately 1.5% of the previous year's estimates and have been both positive and negative.

Changes in commodity prices also affect our reserve quantities. Between 2012 and 2013, oil and natural gas prices used to calculate reserve quantities in our year-end proved reserve report increased, resulting in an increase in our proved reserves of 3.0 MMBOE. Between 2013 and 2014, oil and natural gas prices used to calculate year-end proved reserves decreased, resulting in a decrease in our proved reserves of 0.7 MMBOE. These changes in quantities affect our DD&A rate, and the combined effect of changes in quantities and commodity prices impacts our full cost ceiling test calculation. For example, we estimate that a 5% increase in our estimate of proved reserves quantities would have lowered our fourth quarter 2014 DD&A rate from $18.17 per BOE to approximately $17.33 per BOE, and a 5% decrease in our proved reserve quantities would have increased our DD&A rate to approximately $19.09 per BOE. Also, reserve quantities and their ultimate values, determined solely by our lenders, are the primary factors in determining the maximum borrowing base under our Bank Credit Facility.

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized cost or the cost center ceiling. The cost center ceiling is defined as (1) the present value of estimated future net revenues from proved reserves before future abandonment costs (discounted at 10%), based on the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period; plus (2) the cost of properties not being amortized; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) related income tax effects. Our future net revenues from proved reserves are not reduced for development costs related to the cost of drilling for and developing CO_2 reserves nor for those related to the cost of constructing CO_2 pipelines, as those costs have already been incurred by the Company. Therefore, we include in the ceiling test, as a reduction of future net revenues, that portion of our capitalized CO_2 costs related to CO_2 reserves and CO_2 pipelines that we estimate will be consumed in the process of producing our proved oil and natural gas reserves. The fair value of our oil and natural gas derivative contracts is not included in the ceiling test, as we do not designate these contracts as hedge instruments for accounting purposes.

We did not have a full cost pool ceiling test write-down in 2014, 2013 or 2012. However, a decline of approximately 15% or more in the value of the cost center ceiling would have resulted in an impairment during the year ended December 31, 2014. Crude oil prices increased between 2012 and 2013 and decreased during 2014. Although NYMEX prices decreased precipitously in the fourth quarter of 2014, ending the year at approximately $53 per Bbl, first-day-of-the-month NYMEX oil prices during 2014 averaged $94.99 per Bbl during the year. First-day-of-the-month unweighted average NYMEX natural gas prices during 2014 of $4.30 per MMBtu were higher than unweighted average natural gas prices for 2013. Commodity prices have historically been volatile and are expected to continue to be so in the future. If oil and natural gas prices were to remain at or near these late 2014 and early 2015 levels in subsequent periods, we would likely begin recording write-downs due to the full cost ceiling test in the first or second quarter of 2015, and also in subsequent quarterly periods if prices remain low. The possibility and amount of any future write-down is difficult to predict, and will depend, in part, upon the oil and natural gas prices utilized in the ceiling test, the incremental proved reserves that might be added during each period, and future capital expenditures and operating costs.

We exclude certain unevaluated costs from the amortization base and full cost ceiling test pending the determination of whether proved reserves can be assigned to such properties. These costs are transferred to the full cost amortization base in the course of these properties being developed, tested and evaluated. At least annually, we test these assets for impairment based on an evaluation of management's expectations of future pricing, evaluation of lease expiration terms, and planned project development activities. We did not have an impairment of our unevaluated costs for the years ended December 31, 2014, 2013 or 2012.

Tertiary Injection Costs

Our tertiary operations are conducted in reservoirs that have already produced significant amounts of oil over many years; however, in accordance with the rules for recording proved reserves, we cannot recognize proved reserves associated with enhanced recovery techniques such as CO_2 injection until we can demonstrate production resulting from the tertiary process or unless the field is analogous to an existing flood. Our costs associated with the CO_2 we produce (or acquire) and inject are principally our cash out-of-pocket costs of production, transportation and acquisition, and to pay royalties.

We capitalize, as a development cost, injection costs in fields that are in their development stage, which means we have not yet seen incremental oil production due to the CO_2 injections (i.e., a production response). These capitalized development costs will be included in our unevaluated property costs if there are not already proved tertiary reserves in that field. After we see a production response to the CO_2 injections (i.e., the production stage), injection costs will be expensed as incurred, and any previously deferred unevaluated development costs will become subject to depletion upon recognition of proved tertiary reserves. During 2014, 2013 and 2012, we capitalized $20.7 million, $38.7 million and $36.8 million, respectively, of tertiary injection costs associated with our tertiary projects.

Income Taxes

We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Our federal and state income tax returns are generally not prepared or filed before the consolidated financial statements are prepared; therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and net operating loss carryforwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we finalize our income tax returns. Further, we must assess the likelihood that we will be able to recover or utilize our deferred tax assets (primarily our enhanced oil recovery credits and state loss carryforwards). If recovery is not likely, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover, which would result in an increase to our income tax expense. As of December 31, 2014, we believe that all of our recognized deferred tax assets will ultimately be recovered. If our estimates and judgments change regarding our ability to utilize our deferred tax assets, our tax provision would increase in the period it is determined that recovery is not likely. A 1% increase in our effective tax rate would have increased our calculated income tax expense by approximately $10.2 million, $6.4 million and $8.6 million for the years ended December 31, 2014, 2013 and 2012, respectively. See Note 6, *Income Taxes,* to the Consolidated Financial Statements and *Results of Operations – Income Taxes* above for further information concerning our income taxes.

Fair Value Estimates

The FASC defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. It does not require us to make any new fair value measurements, but rather establishes a fair value hierarchy that prioritizes the inputs to the valuation techniques used to measure fair value. Level 1 inputs are given the highest priority in the fair value hierarchy, as they represent observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date, while Level 3 inputs are given the lowest priority, as they represent unobservable inputs that are not corroborated by market data. Valuation techniques that maximize the use of observable inputs are favored. See Note 10, *Fair Value Measurements,* to the Consolidated Financial Statements for disclosures regarding our recurring fair value measurements.

Significant uses of fair value measurements include:

- allocation of the purchase price paid to acquire businesses to the assets acquired and liabilities assumed in those acquisitions;
- assessment of impairment of long-lived assets;
- assessment of impairment of goodwill; and
- recorded value of commodity derivative instruments.

Acquisitions

Under the acquisition method of accounting for business combinations, the purchase price paid to acquire a business is allocated to its assets and liabilities based on the estimated fair values of the assets acquired and liabilities assumed as of the date of acquisition. The FASC *Fair Value Measurement* topic defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (often referred to as the "exit price"). A fair value measurement is based on the assumptions of market participants and not those of the reporting entity. Therefore, entity-specific intentions do not impact the measurement of fair value unless those assumptions are consistent with market participant views.

The excess of the purchase price over the fair value (as defined by the FASC *Fair Value Measurement* topic) of the net tangible and identifiable intangible assets acquired is recorded as goodwill. A significant amount of judgment is involved in estimating the individual fair values involving long-term tangible assets, identifiable intangible assets and long-term asset retirement obligations. We use all available information to estimate the fair values of assets acquired and liabilities assumed in an acquisition and engage a third-party consultant to review certain assumptions utilized in our valuations.

Specifically, the FASC *Fair Value Measurement* topic requires us to value oil properties recoverable through enhanced oil recovery by estimating the cost a third-party market participant would pay for CO_2. A third party's economics and access to CO_2 are substantially different in our operating regions than our own, as CO_2 is limited and there may be no known CO_2 available in a given area except through our own sources. These factors generally result in our estimation of the cost of CO_2 to a market participant being higher than our cost. Because of our strategic advantage relating to CO_2 supply and associated infrastructure, a third party's economics (the required basis for allocating values) for a potential EOR flood will be less than ours. Therefore, we cannot attribute much, if any, of our purchase price relating to the future EOR flood to unevaluated properties, even though we may have attributed value to the future flood when we made the purchase decision. As such, we must attribute the unallocated purchase price to goodwill, which has resulted in our recognition of more goodwill than most of our industry peers.

The fair values used to allocate the purchase price of an acquisition are often estimated using the expected present value of future cash flows method, which requires us to project related future cash inflows and outflows and apply an appropriate discount rate. The estimates used in determining fair values are based on assumptions believed to be reasonable but that are inherently uncertain. Accordingly, actual results may differ from the projected results used to determine fair value.

Impairment Assessment of Goodwill

We test goodwill for impairment annually during the fourth quarter, or between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. The need to test for impairment can be based on several indicators, including a significant reduction in prices of oil or natural gas, a full-cost ceiling write-down of oil and natural gas properties, unfavorable adjustments to reserves, significant changes in the expected timing of production, other changes to contracts or changes in the regulatory environment.

Goodwill is tested for impairment at the reporting unit level. Denbury applies SEC full cost accounting rules, under which the acquisition cost of oil and gas properties is recognized on a cost center basis (country), of which Denbury has only one cost center (United States). Goodwill is assigned to this single reporting unit.

In each period that a goodwill impairment test is performed, we have the option to assess qualitative factors to determine if it is more likely than not that our reporting unit's fair value is less than its carrying amount. The following events and circumstances are certain of the qualitative factors we consider in evaluating whether it is more likely than not the fair value of our reporting unit is less than its carrying amount:

- Macroeconomic conditions, such as deterioration in general economic conditions, limitations on accessing capital, or other developments in equity and credit markets;
- Industry and market conditions, such as deterioration in the environment in which we operate, including significant declines in oil prices, inability to access oil field equipment and/or qualified personnel and regulations impacting the oil and natural gas industry, among others;
- Cost factors, such as increases in power and labor costs;
- Overall financial performance, such as negative or declining cash flows or a decline in actual or forecasted revenues or earnings;
- Other relevant Company-specific events, such as material changes in management or key personnel, a change in strategy or litigation;
- Material events, such as a change in the composition or carrying amount of our reporting unit's net assets, including acquisitions and dispositions; and
- Consideration of the relationship of our market capitalization to our book value, as well as a sustained decrease in our share price.

If we determine that it is more likely than not that our reporting unit's fair value is less than its carrying amount, we will proceed to step one of the two-step quantitative goodwill assessment, in which we perform a calculation to compare the fair value of our reporting unit to its carrying cost. In any given period, we have the option to bypass the qualitative assessment and proceed directly to step one of the two-step quantitative goodwill impairment test.

We performed our goodwill impairment assessment as of December 31, 2014. Because our enterprise value (combined market capitalization plus a control premium of 10% and the fair value of our long-term debt) was below the combined book value of our stockholders' equity and long-term debt as of December 31, 2014, we were required to proceed to step two of the goodwill impairment test. A key factor resulting in the deficit of enterprise value to book value is pricing utilized in assessing impairment of our oil and natural gas properties through the full cost pool ceiling test. As prescribed by FASC Topic 932, *Extractive Industries – Oil and Gas,* the ceiling test was calculated using the first-day-of-the-month unweighted average of NYMEX oil prices of $94.99 per Bbl during 2014, rather than oil and natural gas prices as of December 31, 2014. If the ceiling test had been performed using December 31, 2014, oil and natural gas prices, our oil and natural gas properties balance would have reflected a write-down, reducing the amount by which our book value of stockholders' equity and long-term debt would have exceeded our enterprise value.

As a result, we performed the step two quantitative assessment to assign the fair value of the reporting unit (enterprise value) to its assets and liabilities and calculate the implied fair value of goodwill as the excess of fair value of the reporting unit over the amounts assigned to the asset and liabilities. We based our fair value estimates on projected financial information that we believe to be reasonable. However, actual results may differ from those projections.

Oil and natural gas reserves, which represent the most significant assets requiring valuation, were estimated using the expected present value of future cash flows method based on December 31, 2014, NYMEX oil and natural gas futures prices for the next five years, which ranged from approximately $56 per Bbl to $70 per Bbl for oil and $3 per MMBtu to $4 per MMBtu for natural gas, adjusted for current price differentials. Projections of future cash flows were based on non-pricing assumptions used in our 2014 year-end reserves process, adjusted where applicable for the December 31, 2014, oil and natural gas futures prices used in the goodwill impairment assessment and the inclusion of cash flows associated with probable and possible oil and natural gas reserves. More specifically, projections of estimated quantities of oil and natural gas reserves, projections of future rates of production, timing and amount of future development and operating costs (including our announced reduction in planned 2015 capital spending), projected CO_2 availability (including current and potential future industrial sources of CO_2) and cost of CO_2 (adjusted for changes in oil prices for those contracts tied to oil prices), risk adjustment factors applied to probable and possible oil and natural gas reserve cash flows, projected recovery factors of oil and natural gas reserves, and a weighted-average cost of capital rate of 9% per annum applied to all cash flows are key assumptions impacting our estimate of future cash flows. Consistent with a market participant view, we did not assign a separate value to CO_2 properties and pipelines from the value assigned to oil and natural gas properties other than CO_2 reserves associated with existing third-party sales contracts, because CO_2 properties and pipelines are expected to be dedicated to the tertiary flood operations and the lower cost of utilizing our owned assets is reflected in the tertiary oil reserve cash flows.

The implied fair value of goodwill calculated in this quantitative assessment significantly exceeded the corresponding book value of goodwill. Therefore, we did not record any goodwill impairment during 2014, nor have we recorded a goodwill impairment historically. The cushion between the implied fair value of goodwill and book value of goodwill is due to our enterprise value declining at a slower rate than NYMEX oil futures prices, which were used in the step-two valuation of our oil reserves. A significant change in the assumptions noted above, including future oil and natural gas prices, or a significant decrease in our enterprise value could lead to an impairment of goodwill in future periods. For example, calculations based upon future oil and natural gas prices approximately 20% higher than those at December 31, 2014, without a change in enterprise value or change in other cash flow assumptions, likely would have required a partial impairment of goodwill at December 31, 2014.

Impairment Assessment of Long-lived Assets

We test long-lived assets for impairment that are not subject to our quarterly full cost pool ceiling test, including a portion of our capitalized CO_2 properties and pipelines, the Riley Ridge gas processing facility and our related intangible assets, whenever events or changes in circumstances indicate that the carrying value may not be recoverable. The factors we assess to determine if a long-lived asset impairment test is necessary include, among other factors, a significant adverse change in the business climate that could affect the value of a long-lived asset, a significant decrease in the market price of an asset group, a significant adverse change in the extent or manner in which a long-lived asset (asset group) is being used or in its physical condition, or a current-period operating or cash flow loss combined with a history of operating or cash flow losses or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset (asset group).

We perform our long-lived asset impairment test by comparing the net carrying costs of our two long-lived asset groups (1) Gulf Coast region and (2) Rocky Mountain region) to the respective expected future undiscounted net cash flows that are supported by these long-lived assets, which include (1) the production of our probable and possible oil and natural gas reserves and (2) the sale of non-hydrocarbons (CO_2 and helium) to third parties. If the undiscounted net cash flows are below the net carrying costs for an asset group, the Company must record an impairment loss by the amount, if any, that net carrying costs exceed the fair value of the long-lived asset group.

Significant assumptions impacting expected future undiscounted net cash flows include projections of future oil and natural gas prices (management's assumption of oil prices of $75 per Bbl and gas futures pricing were used for the December 31, 2014, analysis), projections of estimated quantities of oil and natural gas reserves, projections of future rates of production, timing and amount of future development and operating costs, projected availability and cost of CO_2, projected recovery factors of tertiary reserves and risk-adjustment factors applied to the cash flows. Given the significant decline in oil prices in the fourth quarter of 2014, we performed step one of the long-lived asset impairment test for both asset groups. The undiscounted net cash flows for our asset groups significantly exceeded the net carrying costs; thus, step two of the impairment test was not required and no impairment was recorded. Changes in the assumptions noted above or changes in management's intended use of assets or asset groups could cause step two of the long-lived asset impairment test to be performed, which could result in the recording of long-lived asset impairments.

Oil and Natural Gas Derivative Contracts

We enter into oil and natural gas derivative contracts to mitigate our exposure to commodity price risk associated with future oil and natural gas production. These contracts have historically consisted of options, in the form of price floors, collars or three-way collars, fixed-price swaps and fixed-price swaps enhanced with a sold put. Our derivative financial instruments are recorded on the balance sheet as either an asset or liability measured at fair value. The valuation methods used to measure the fair values of these assets and liabilities require considerable management judgment and estimates to derive the inputs necessary to determine fair value estimates, such as forward prices for commodities, interest rates, volatility factors and credit worthiness, as well as other relevant economic measures. We do not apply hedge accounting to our commodity derivative contracts under the FASC *Derivatives and Hedging* topic; accordingly, changes in the fair value of these instruments are recognized in earnings on a quarterly basis instead of charging the effective portion to other comprehensive income and the balance to earnings. While we may experience more volatility in our net income than if we were to apply hedge accounting treatment as permitted by the FASC *Derivatives and Hedging* topic, we believe that for us, the benefits associated with applying hedge accounting do not outweigh the cost, time and effort to comply with hedge accounting.

Environmental and Litigation Contingencies

The Company makes judgments and estimates in recording liabilities for contingencies such as environmental remediation or ongoing litigation. Liabilities are recorded when it is both probable that a loss has been incurred and such loss is reasonably estimable. Assessments of liabilities are based on information obtained from independent and in-house experts, loss experience in similar situations, actual costs incurred, and other case-by-case factors. Actual costs can vary from such estimates for a variety of reasons. The costs of environmental remediation or litigation can vary from estimates due to new developments regarding the facts and circumstances of each event, including in the case of environmental remediation, the timing of remediation, our understanding of the environmental impact, remediation methods available, and regulatory requirements, and in the case of litigation, differing interpretations of laws and facts and assessments of damages asserted and/or incurred.

Use of Estimates

See Note 1, *Significant Accounting Policies,* to the Consolidated Financial Statements for a discussion of our use of estimates.

Recent Accounting Pronouncements

See Note 1, *Significant Accounting Policies,* to the Consolidated Financial Statements for a discussion of recent accounting pronouncements.

FORWARD-LOOKING INFORMATION

The statements contained in this Annual Report on Form 10-K that are not historical facts, including, but not limited to, statements found in the sections entitled "Business and Properties" and "Management's Discussion and Analysis of Financial Condition and Results of Operations," are forward-looking statements, as that term is defined in Section 21E of the Securities and Exchange Act of 1934, as amended, that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, projected future hydrocarbon prices, the length or severity of the oil price downturn in late 2014 and early 2015, assumptions based on current and projected oil and gas costs, liquidity, availability of capital, borrowing capacity, estimated future cash flows, predicted availability of advantageous commodity derivative contracts or the cash flow benefits therefrom, forecasted capital expenditures, drilling activity or methods including the timing and location thereof, estimated timing of commencement of CO_2 flooding of particular fields or areas, or the timing of pipeline construction or completion or the cost thereof, dates of completion of to-be-constructed industrial plants and the initial date of capture of CO_2 from such plants, timing of CO_2 injections and initial production responses in tertiary flooding projects, acquisition plans and proposals and dispositions, development activities, finding costs, cost savings, capital budgets, production rates and volumes or forecasts thereof, assumptions regarding payment of future cash dividends to shareholders, the rate thereof, or the sustainability or growth of future payments, hydrocarbon reserve quantities and values, CO_2 reserves, helium reserves, potential reserves, percentages of recoverable original oil in place, regulatory matters, prospective legislation affecting the oil and gas industry, mark-to-market values, possible asset impairments, competition, long-term forecasts of production, finding costs, rates of return, estimated costs, or changes in costs, future capital expenditures and overall economics and other variables surrounding our operations and future plans. Such forward-looking statements generally are accompanied by words such as "plan," "estimate," "expect," "predict," "anticipate," "projected," "should," "assume," "believe," "target" or other words that convey the uncertainty of future events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates and assumptions and is subject to a number of risks and uncertainties that could significantly affect current plans, anticipated actions, the timing of such actions and our financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by us or on our behalf. Among the factors that could cause actual results to differ materially are fluctuations of the prices received or demand for our oil and natural gas; effects of our indebtedness; success of our risk management techniques; inaccurate cost estimates; availability of and fluctuations in the prices of goods and services; the uncertainty of drilling results and reserve estimates; operating hazards; disruption of operations and damages from hurricanes or tropical storms; acquisition risks; requirements for capital or its availability; conditions in the financial and credit markets; general economic conditions; competition and government regulations; and unexpected delays, as well as the risks and uncertainties inherent in oil and gas drilling and production activities or that are otherwise discussed in this annual report, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in our other public reports, filings and public statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The information required by Item 7A is set forth under *Market Risk Management* in Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

Item 8. Financial Statements and Supplementary Information

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Denbury Resources Inc.:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Denbury Resources Inc. and its subsidiaries at December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Dallas, Texas
February 27, 2015

CONSOLIDATED BALANCE SHEETS

In thousands, except par value and share data	December 31, 2014	December 31, 2013
Assets		
Current assets		
Cash and cash equivalents	$ 23,153	$ 12,187
Accrued production receivable	181,761	262,047
Trade and other receivables, net	156,955	78,295
Derivative assets	440,359	5
Deferred tax assets	—	52,754
Other current assets	10,452	9,271
Total current assets	812,680	414,559
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved properties	9,782,337	8,945,326
Unevaluated properties	918,406	780,481
CO_2 properties	1,162,538	1,117,167
Pipelines and plants	2,269,564	2,209,560
Other property and equipment	468,051	466,969
Less accumulated depletion, depreciation, amortization and impairment	(4,248,652)	(3,668,225)
Net property and equipment	10,352,244	9,851,278
Derivative assets	66,187	9,942
Goodwill	1,283,590	1,283,590
Other assets	213,101	229,368
Total assets	$12,727,802	$11,788,737
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 394,758	$ 410,543
Oil and gas production payable	128,170	174,677
Derivative liabilities	—	53,822
Deferred tax liabilities	81,727	—
Current maturities of long-term debt	35,470	36,157
Total current liabilities	640,125	675,199
Long-term liabilities		
Long-term debt, net of current portion	3,535,900	3,260,625
Asset retirement obligations	126,411	119,888
Derivative liabilities	—	3,413
Deferred tax liabilities	2,694,842	2,399,294
Other liabilities	26,668	28,912
Total long-term liabilities	6,383,821	5,812,132
Commitments and contingencies (Note 11)		
Stockholders' equity		
Preferred stock, $.001 par value, 25,000,000 shares authorized, none issued and outstanding	—	—
Common stock, $.001 par value, 600,000,000 shares authorized; 411,779,911 and 409,215,573 shares issued, respectively	412	409
Paid-in capital in excess of par	3,230,418	3,186,714
Retained earnings	3,392,465	2,844,432
Accumulated other comprehensive loss	(209)	(276)
Treasury stock, at cost, 58,415,507 and 46,710,896 shares, respectively	(919,230)	(729,873)
Total stockholders' equity	5,703,856	5,301,406
Total liabilities and stockholders' equity	$12,727,802	$11,788,737

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF OPERATIONS

In thousands, except per share data	Year Ended December 31, 2014	2013	2012
Revenues and other income			
Oil, natural gas, and related product sales	$2,372,473	$2,466,234	$2,409,867
CO_2 and helium sales and transportation fees	44,643	27,950	26,453
Interest income and other income	18,089	22,943	20,152
Total revenues and other income	2,435,205	2,517,127	2,456,472
Expenses			
Lease operating expenses	647,559	730,574	532,359
Marketing and plant operating expenses	64,379	49,246	52,836
CO_2 and helium discovery and operating expenses	25,222	16,916	14,694
Taxes other than income	169,701	176,231	160,016
General and administrative expenses	158,343	145,211	144,019
Interest, net of amounts capitalized of $24,202, $79,253 and $77,432, respectively	183,003	140,709	153,581
Depletion, depreciation, and amortization	592,972	509,943	507,538
Commodity derivatives expense (income)	(555,255)	41,024	(4,834)
Loss on early extinguishment of debt	113,908	44,651	—
Impairment of assets	—	—	17,515
Other expenses	12,816	20,242	21,891
Total expenses	1,412,648	1,874,747	1,599,615
Income before income taxes	1,022,557	642,380	856,857
Income tax provision	387,066	232,783	331,497
Net income	$ 635,491	$ 409,597	$ 525,360
Net income per common share			
Basic	$ 1.82	$ 1.12	$ 1.36
Diluted	$ 1.81	$ 1.11	$ 1.35
Dividends declared per common share	$ 0.25	$ —	$ —
Weighted average common shares outstanding			
Basic	348,962	366,659	385,205
Diluted	351,167	369,877	388,938

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE OPERATIONS

	Year Ended December 31,		
In thousands	2014	2013	2012
Net income	$635,491	$409,597	$525,360
Other comprehensive income, net of income tax			
Interest rate lock derivative contracts reclassified to income, net of tax of $45, $40 and $43, respectively	67	72	70
Total other comprehensive income	67	72	70
Comprehensive income	$635,558	$409,669	$525,430

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

In thousands	Year Ended December 31, 2014	2013	2012
Cash flows from operating activities			
Net income	$ 635,491	$ 409,597	$ 525,360
Adjustments to reconcile net income to cash flows from operating activities			
Depletion, depreciation, and amortization	592,972	509,943	507,538
Deferred income taxes	429,973	222,526	255,743
Stock-based compensation	30,513	33,003	29,310
Commodity derivatives expense (income)	(555,255)	41,024	(4,834)
Settlements of commodity derivatives	1,421	(662)	17,880
Loss on early extinguishment of debt	113,908	44,651	—
Amortization of debt issuance costs and discounts	13,476	14,023	14,695
Impairment of assets	—	—	17,515
Other, net	6,311	(2,318)	16,917
Changes in assets and liabilities, net of effects from acquisitions			
Accrued production receivable	80,285	(15,085)	36,234
Trade and other receivables	(78,469)	4,981	45,836
Other current and long-term assets	3,174	10,462	7,688
Accounts payable and accrued liabilities	501	91,816	5,828
Oil and natural gas production payable	(46,506)	12,731	(23,460)
Other liabilities	(4,970)	(15,497)	(41,359)
Net cash provided by operating activities	1,222,825	1,361,195	1,410,891
Cash flows from investing activities			
Oil and natural gas capital expenditures	(946,846)	(900,221)	(1,122,615)
Acquisitions of oil and natural gas properties	(8,773)	(9,243)	(156,082)
Bakken exchange transaction	—	(10,385)	281,669
CO_2 capital expenditures	(48,134)	(93,744)	(131,043)
Pipelines and plants capital expenditures	(72,151)	(184,286)	(330,417)
Purchases of other assets	(3,197)	(65,987)	(25,765)
Net proceeds from sales of oil and natural gas properties and equipment	3,453	8,037	34,750
Net proceeds from sale of short-term investments	—	—	83,545
Other	(1,107)	(19,480)	(10,883)
Net cash used in investing activities	(1,076,755)	(1,275,309)	(1,376,841)
Cash flows from financing activities			
Bank repayments	(2,609,000)	(1,550,000)	(1,555,000)
Bank borrowings	2,664,000	1,190,000	1,870,000
Repayment of senior subordinated notes	(997,345)	(651,270)	—
Premium paid on repayment of senior subordinated notes	(101,342)	(36,475)	—
Net proceeds from issuance of senior subordinated notes	1,250,000	1,200,000	—
Costs of debt financing	(24,407)	(20,161)	(34)
Common stock repurchase program	(211,356)	(281,958)	(251,480)
Cash dividends paid	(87,044)	—	—
Other	(18,610)	(22,346)	(17,718)
Net cash provided by (used in) financing activities	(135,104)	(172,210)	45,768
Net increase (decrease) in cash and cash equivalents	10,966	(86,324)	79,818
Cash and cash equivalents at beginning of year	12,187	98,511	18,693
Cash and cash equivalents at end of year	$ 23,153	$ 12,187	$ 98,511

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

Dollar amounts in thousands	COMMON STOCK ($.001 Par Value) Shares	COMMON STOCK ($.001 Par Value) Amount	Paid-In CAPITAL IN Excess of Par	Retained Earnings	Accumulated OTHER Comprehensive Income (Loss)	TREASURY STOCK (at cost) Shares	TREASURY STOCK (at cost) Amount	Total Equity
Balance – December 31, 2011	402,946,070	$403	$3,090,374	$1,909,475	$(418)	13,965,673	$(193,336)	$4,806,498
Stock Repurchase Program	—	—	—	—	—	16,978,008	(266,657)	(266,657)
Issued or purchased pursuant to employee stock compensation plans	3,197,476	3	6,021	—	—	—	—	6,024
Issued pursuant to employee stock purchase plan	—	—	1,607	—	—	(815,385)	11,653	13,260
Issued pursuant to directors' compensation plan	19,648	—	321	—	—	—	—	321
Stock-based compensation	—	—	37,897	—	—	—	—	37,897
Income tax benefit from equity awards	—	—	241	—	—	—	—	241
Tax withholding – stock compensation	—	—	—	—	—	472,966	(8,125)	(8,125)
Derivative contracts, net	—	—	—	—	70	—	—	70
Net income	—	—	—	525,360	—	—	—	525,360
Balance – December 31, 2012	406,163,194	406	3,136,461	2,434,835	(348)	30,601,262	(456,465)	5,114,889
Stock Repurchase Program	—	—	—	—	—	16,468,648	(277,768)	(277,768)
Issued or purchased pursuant to employee stock compensation plans	3,038,767	3	5,486	—	—	—	—	5,489
Issued pursuant to employee stock purchase plan	—	—	1,844	—	—	(860,901)	13,260	15,104
Issued pursuant to directors' compensation plan	13,612	—	344	—	—	—	—	344
Stock-based compensation	—	—	42,091	—	—	—	—	42,091
Income tax benefit from equity awards	—	—	488	—	—	—	—	488
Tax withholding – stock compensation	—	—	—	—	—	501,887	(8,900)	(8,900)
Derivative contracts, net	—	—	—	—	72	—	—	72
Net income	—	—	—	409,597	—	—	—	409,597
Balance – December 31, 2013	409,215,573	409	3,186,714	2,844,432	(276)	46,710,896	(729,873)	5,301,406
Stock Repurchase Program	—	—	—	—	—	12,398,017	(200,369)	(200,369)
Issued or purchased pursuant to employee stock compensation plans	2,541,809	3	7,020	—	—	—	—	7,023
Issued pursuant to employee stock purchase plan	—	—	(3,272)	—	—	(1,247,156)	19,630	16,358
Issued pursuant to directors' compensation plan	22,529	—	412	—	—	—	—	412
Stock-based compensation	—	—	39,532	—	—	—	—	39,532
Income tax benefit from equity awards	—	—	12	—	—	—	—	12
Tax withholding – stock compensation	—	—	—	—	—	553,750	(8,618)	(8,618)
Derivative contracts, net	—	—	—	—	67	—	—	67
Cash dividends declared ($0.25 per common share)	—	—	—	(87,458)	—	—	—	(87,458)
Net income	—	—	—	635,491	—	—	—	635,491
Balance – December 31, 2014	411,779,911	$412	$3,230,418	$3,392,465	$(209)	58,415,507	$(919,230)	$5,703,856

See accompanying Notes to Consolidated Financial Statements.

Note 1. Significant Accounting Policies

Organization and Nature of Operations

Denbury Resources Inc., a Delaware corporation, is an independent oil and natural gas company with operations focused in two key operating areas: the Gulf Coast and Rocky Mountain regions. Our goal is to increase the value of our properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis relating to CO_2 enhanced oil recovery operations.

Principles of Reporting and Consolidation

The consolidated financial statements herein have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP") and include the accounts of Denbury and entities in which we hold a controlling financial interest. Undivided interests in oil and gas joint ventures are consolidated on a proportionate basis. All intercompany balances and transactions have been eliminated.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amount of certain assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during each reporting period. Management believes its estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. Significant estimates underlying these financial statements include (1) the fair value of financial derivative instruments; (2) the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties, the related present value of estimated future net cash flows therefrom and the ceiling test; (3) future net cash flow estimates used in the impairment assessment of goodwill and long-lived assets; (4) the estimated quantities of proved and probable CO_2 reserves used to compute depletion of CO_2 properties; (5) accruals related to oil and natural gas sales volumes and revenues, capital expenditures and lease operating expenses; (6) the estimated costs and timing of future asset retirement obligations; (7) estimates made in the calculation of income taxes; and (8) estimates made in determining the fair values for purchase price allocations, including goodwill. While management is not aware of any significant revisions to any of its estimates, there will likely be future revisions to its estimates resulting from matters such as revisions in estimated oil and natural gas volumes, changes in ownership interests, payouts, joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and natural gas industry, many of which require retroactive application. These types of adjustments cannot be currently estimated and will be recorded in the period in which the adjustment occurs.

Cash Equivalents

We consider all highly liquid investments to be cash equivalents if they have maturities of three months or less at the date of purchase.

Oil and Natural Gas Properties

Capitalized Costs. We follow the full cost method of accounting for oil and natural gas properties. Under this method, all costs related to the acquisition, exploration and development of oil and natural gas reserves are capitalized and accumulated in a single cost center representing our activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and nonproductive wells, capitalized interest on qualifying projects, and general and administrative expenses directly related to exploration and development activities, and do not include any costs related to production, general corporate overhead or similar activities. We assign the purchase price of oil and natural gas properties we acquire to proved and unevaluated properties based on the estimated fair values as defined in the Financial Accounting Standards Board Codification ("FASC") *Fair Value Measurement* topic. Proceeds received from disposals are credited against accumulated costs except when the sale represents a significant disposal of reserves, in which case a gain or loss would be recognized. A disposal of 25% or more of our proved reserves would be considered significant.

Depletion and Depreciation. The costs capitalized, including production equipment and future development costs, are depleted or depreciated using the unit-of-production method, based on proved oil and natural gas reserves as determined by independent petroleum engineers. Oil and natural gas reserves are converted to equivalent units on a basis of 6,000 cubic feet of natural gas to one barrel of crude oil.

Under full cost accounting, we may exclude certain unevaluated costs from the amortization base pending determination of whether proved reserves can be assigned to such properties. The costs classified as unevaluated are transferred to the full cost amortization base as the properties are developed, tested and evaluated.

Ceiling Test. The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized cost or the cost center ceiling. The cost center ceiling is defined as (1) the present value of estimated future net revenues from proved oil and natural gas reserves before future abandonment costs (discounted at 10%), based on the average first-day-of-the-month oil and natural gas price for each month during a 12-month rolling period prior to the end of a particular reporting period; plus (2) the cost of properties not being amortized; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) related income tax effects. Our future net revenues from proved oil and natural gas reserves are not reduced for development costs related to the cost of drilling for and developing CO_2 reserves nor those related to the cost of constructing CO_2 pipelines, as those costs have previously been incurred by the Company. Therefore, we include in the ceiling test, as a reduction of future net revenues, that portion of our capitalized CO_2 costs related to CO_2 reserves and CO_2 pipelines that we estimate will be consumed in the process of producing our proved oil and natural gas reserves. The fair value of our oil and natural gas derivative contracts is not included in the ceiling test, as we do not designate these contracts as hedge instruments for accounting purposes. The cost center ceiling test is prepared quarterly. We did not have a ceiling test write-down during the years ended December 31, 2014, 2013 or 2012. If oil and natural gas prices were to remain at or near late 2014 and early 2015 levels in subsequent periods, which are significantly lower than our 2014 average first-day-of-the-month oil and natural gas prices, we would likely begin recording write-downs due to the full cost ceiling test in the first or second quarter of 2015, and also in subsequent quarterly periods if prices remain low.

Joint Interest Operations. Substantially all of our oil and natural gas exploration and production activities are conducted jointly with others. These financial statements reflect only our proportionate interest in such activities, and any amounts due from other partners are included in trade receivables.

Tertiary Injection Costs. Our tertiary operations are conducted in reservoirs that have already produced significant amounts of oil over many years; however, in accordance with the SEC rules and regulations for recording proved reserves, we cannot recognize proved reserves associated with enhanced recovery techniques, such as CO_2 injection, until we can demonstrate production resulting from the tertiary process or unless the field is analogous to an existing flood.

We capitalize, as a development cost, injection costs in fields that are in their development stage, which means we have not yet seen incremental oil production due to the CO_2 injections (i.e., a production response). These capitalized development costs are included in our unevaluated property costs if there are not already proved tertiary reserves in that field. After we see a production response to the CO_2 injections (i.e., the production stage), injection costs are expensed as incurred, and once proved reserves are recognized, previously deferred unevaluated development costs become subject to depletion.

CO_2 Properties

We own and produce CO_2 reserves, a non-hydrocarbon resource, that are used in our tertiary oil recovery operations on our own behalf and on behalf of other interest owners in enhanced recovery fields, with a portion sold to third-party industrial users. We record revenue from our sales of CO_2 to third parties when it is produced and sold. Expenses related to the production of CO_2 are allocated between volumes sold to third parties and volumes consumed internally that are directly related to our tertiary production. The expenses related to third-party sales are recorded in "CO_2 and helium discovery and operating expenses," and the expenses related to internal use are recorded in "Lease operating expenses" in the Consolidated Statements of Operations or are capitalized as oil and gas properties in our Consolidated Balance Sheets, depending on the stage of the tertiary flood that is receiving the CO_2 (see *Tertiary Injection Costs* above for further discussion).

Costs incurred to search for CO_2 are expensed as incurred until proved or probable reserves are established. Once proved or probable reserves are established, costs incurred to obtain those reserves are capitalized and classified as "CO_2 properties" on our Consolidated Balance Sheets. Capitalized CO_2 costs are aggregated by geologic formation and depleted on a unit-of-production basis over proved and probable reserves.

We own certain interests in the Riley Ridge Federal Unit in Wyoming ("Riley Ridge"), which contains helium and CO_2 reserves (non-hydrocarbon resources) as well as natural gas reserves (a hydrocarbon resource). It is not possible to separately identify the capitalized costs related to the development of each product in the commingled gas stream; thus, these costs are allocated to each product based on the relative future revenue value of each product line and classified accordingly on the Consolidated Balance Sheets.

Pipelines and Plants

CO_2 used in our tertiary floods is transported to our fields through CO_2 pipelines. Costs of CO_2 pipelines under construction are not depreciated until the pipelines are placed into service. Pipelines are depreciated on a straight-line basis over their estimated useful lives, which range from 15 to 50 years.

Pipelines and plants include the Riley Ridge gas processing facility in southwestern Wyoming. Individual components of the Riley Ridge gas processing facility are depreciated on a straight-line basis over their estimated useful lives, which range from 20 to 50 years.

Property and Equipment – Other

Other property and equipment, which includes furniture and fixtures, vehicles, computer equipment and software, and capitalized leases, is depreciated principally on a straight-line basis over each asset's estimated useful life. Vehicles and furniture and fixtures are generally depreciated over a useful life of five to ten years, and computer equipment and software are generally depreciated over a useful life of three to five years. Leasehold improvements are amortized over the shorter of the estimated useful life or the remaining lease term.

Leased property meeting certain capital lease criteria is capitalized, and the present value of the related lease payments is recorded as a liability. Amortization of capitalized leased assets is computed using the straight-line method over the shorter of the estimated useful life or the initial lease term.

Maintenance and repair costs that do not extend the useful life of the property or equipment are charged to expense as incurred.

Goodwill and Other Intangible Assets

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the acquisition of a business. Goodwill is not amortized; rather, it is tested for impairment annually during the fourth quarter and when events or changes in circumstances indicate that it is more likely than not the fair value of a reporting unit with goodwill has been reduced below its carrying value. The impairment test requires allocating goodwill and other assets and liabilities to reporting units. However, we have only one reporting unit. To assess impairment, we have the option to qualitatively assess if it is more likely than not that the fair value of the reporting unit is less than the carrying value. Absent a qualitative assessment, or, through the qualitative assessment, if we determine it is more likely than not that the fair value of the reporting unit is less than the carrying value, a quantitative assessment is prepared to calculate the fair market value of the reporting unit. If it is determined that the fair value of the reporting unit is less than the carrying value, the recorded goodwill is impaired to its implied fair value with a charge to operating expense. We performed our goodwill impairment assessment as of December 31, 2014. Because our enterprise value (combined market capitalization plus a control premium of 10% and the fair value of our long-term debt) was below the book value of our stockholders' equity and long-term debt as of December 31, 2014, we were required to proceed to step two of the goodwill impairment test.

In the step two quantitative assessment, we assigned the fair value of the reporting unit (enterprise value) to its assets and liabilities and calculated the implied fair value of goodwill as the excess of fair value of the reporting unit over the amounts assigned to the assets and liabilities. Oil and natural gas reserves, which represent the most significant assets requiring valuation, were estimated using the expected present value of future net cash flows method based on December 31, 2014, NYMEX oil and natural gas futures prices for the next five years, adjusted for current price differentials. In addition to future oil and natural gas pricing, the most significant assumptions impacting the projections of future net cash flows include projections of estimated quantities of oil and natural gas reserves, projections of future rates of production, timing and amount of future development and operating costs, projected availability and cost of CO_2, risk adjustment factors applied to probable and possible oil and natural gas reserve cash flows, projected recovery factors of oil and natural gas reserves, and a weighted-average cost of capital discount rate applied to all cash flows. The implied fair value of goodwill calculated in this quantitative assessment significantly exceeded the corresponding book value of goodwill. Therefore, we did not record any goodwill impairment during 2014, nor have we recorded a goodwill impairment historically.

Our intangible assets subject to amortization primarily consist of amounts assigned in purchase accounting to helium production rights at Riley Ridge and a CO_2 purchase contract with ConocoPhillips to offtake CO_2 from the Lost Cabin gas plant in Wyoming and are included in our Consolidated Balance Sheets under the caption "Other assets." We amortize our helium production rights on a unit-of-production basis over the life of the estimated helium reserves and amortize the CO_2 contract intangible asset on a straight-line basis over the contract term. Total amortization expense related to these assets was $2.3 million and $1.3 million during the years ended December 31, 2014 and 2013, respectively. The following table summarizes the carrying values of our intangible assets as of December 31, 2014 and 2013:

In thousands	Helium Production Rights	CO_2 Purchase Contract	Total
December 31, 2014			
Intangible asset value	$55,266	$34,341	$89,607
Accumulated amortization	(15)	(3,625)	(3,640)
Net book value as of December 31, 2014	$55,251	$30,716	$85,967
December 31, 2013			
Intangible asset value	$55,266	$33,931	$89,197
Accumulated amortization	—	(1,319)	(1,319)
Net book value as of December 31, 2013	$55,266	$32,612	$87,878

At December 31, 2014, our estimated amortization expense for our intangible assets subject to amortization over the next five years is as follows:

In thousands	
2015	$2,289
2016	2,488
2017	2,788
2018	2,858
2019	2,833

Impairment Assessment of Long-Lived Assets

The portion of our capitalized CO_2 costs related to CO_2 reserves, CO_2 pipelines, and the Riley Ridge gas processing facility that we estimate will be consumed in the process of producing our proved oil and natural gas reserves is included in the full cost pool ceiling test as a reduction to future net revenues. The remaining net capitalized costs that are not included in the full cost pool ceiling test, and related intangible assets, are subject to long-lived asset impairment testing whenever events or changes in circumstances indicate that the carrying value may not be recoverable.

We perform our long-lived asset impairment test by comparing the net carrying costs of our two long-lived asset groups ((1) Gulf Coast region and (2) Rocky Mountain region) to the respective expected future undiscounted net cash flows that are supported by these long-lived assets which include (1) the production of our probable and possible oil and natural gas reserves and (2) the sale of non-hydrocarbons (CO_2 and helium) to third parties. If the undiscounted net cash flows are below the net carrying costs for an asset group, we must record an impairment loss by the amount, if any, that net carrying costs exceed the fair value of the long-lived asset group.

Given the significant decline in oil prices in the fourth quarter of 2014, we performed a long-lived asset impairment test for both asset groups. Significant assumptions impacting expected future undiscounted net cash flows include projections of future oil and natural gas prices, projections of estimated quantities of oil and natural gas reserves, projections of future rates of production, timing and amount of future development and operating costs, projected availability and cost of CO_2, projected recovery factors of tertiary reserves and risk-adjustment factors applied to the cash flows. The undiscounted net cash flows for our asset groups significantly exceeded the net carrying costs; thus, step two of the impairment test was not required and no impairment was recorded.

Asset Retirement Obligations

In general, our future asset retirement obligations relate to future costs associated with plugging and abandoning our oil, natural gas and CO_2 wells, removing equipment and facilities from leased acreage, and returning land to its original condition. The fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using our credit-adjusted-risk-free interest rate, and a corresponding amount capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted each period, and the capitalized cost is depreciated over the useful life of the related asset. Revisions to estimated retirement obligations will result in an adjustment to the related capitalized asset and corresponding liability. If the liability for an oil or natural gas well is settled for an amount other than the recorded amount, the difference is recorded to the full cost pool, unless significant.

Asset retirement obligations are estimated at the present value of expected future net cash flows. We utilize unobservable inputs in the estimation of asset retirement obligations that include, but are not limited to, costs of labor and materials, profits on costs of labor and materials, the effect of inflation on estimated costs, and the discount rate. Accordingly, asset retirement obligations are considered a Level 3 measurement under the FASC *Fair Value Measurement* topic.

Commodity Derivative Contracts

We utilize oil and natural gas derivative contracts to mitigate our exposure to commodity price risk associated with our future oil and natural gas production. These derivative contracts have historically consisted of options, in the form of price floors, collars or three-way collars, fixed-price swaps and fixed-price swaps enhanced with a sold put. Our derivative financial instruments are recorded on the balance sheet as either an asset or a liability measured at fair value. We do not apply hedge accounting to our commodity derivative contracts; accordingly, changes in the fair value of these instruments are recognized in our Consolidated Statements of Operations in the period of change.

Concentrations of Credit Risk

Our financial instruments that are exposed to concentrations of credit risk consist primarily of cash equivalents, trade and accrued production receivables, and the derivative instruments discussed above. Our cash equivalents represent high-quality securities placed with various investment-grade institutions. This investment practice limits our exposure to concentrations of credit risk. Our trade and accrued production receivables are dispersed among various customers and purchasers; therefore, concentrations of credit risk are limited. We evaluate the credit ratings of our purchasers, and if customers are considered a credit risk, letters of credit are the primary security obtained to support lines of credit. We attempt to minimize our credit risk exposure to the counterparties of our oil and natural gas derivative contracts through formal credit policies, monitoring procedures and diversification. All of our derivative contracts are with parties that are lenders under our bank credit facility (or affiliates of such lenders). There are no margin requirements with the counterparties of our derivative contracts.

Oil and natural gas sales are made on a day-to-day basis or under short-term contracts at the current area market price. We would not expect the loss of any purchaser to have a material adverse effect upon our operations. For the year ended December 31, 2014, three purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company (31%), Plains Marketing LP (13%), and ConocoPhillips (12%). For the year ended December 31, 2013, three purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company (33%), Plains Marketing LP (15%), and Eighty-Eight Oil LLC (10%). For the year ended December 31, 2012, two purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company (39%) and Plains Marketing LP (17%).

Revenue Recognition

Revenue Recognition. Revenue is recognized at the time oil and natural gas is produced and sold. Any amounts due from purchasers of oil and natural gas are included in accrued production receivable.

We follow the sales method of accounting for our oil and natural gas revenue, whereby we recognize revenue on oil or natural gas sold to our purchasers regardless of whether the sales are proportionate to our ownership in the property. A receivable or liability is recognized only to the extent that we have an imbalance on a specific property greater than the expected remaining proved reserves. As of December 31, 2014 and 2013, our aggregate oil and natural gas imbalances were not material to our consolidated financial statements.

We recognize revenue and expenses of purchased producing properties at the time we assume effective control, commencing from either the closing or purchase agreement date, depending on the underlying terms and agreements. We follow the same methodology in reverse when we sell properties by recognizing revenue and expenses of the sold properties until the closing date.

Income Taxes

Income taxes are accounted for using the asset and liability method, under which deferred income taxes are recognized for the future tax effects of temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities using the enacted statutory tax rates in effect at year end. The effect on deferred taxes for a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance for deferred tax assets is recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized.

We recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement.

Net Income Per Common Share

Basic net income per common share is computed by dividing the net income attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income per common share is calculated in the same manner, but includes the impact of potentially dilutive securities. Potentially dilutive securities consist of stock options, stock appreciation rights ("SARs"), nonvested restricted stock and nonvested performance-based equity awards. For each of the three years in the period ended December 31, 2014, there were no adjustments to net income for purposes of calculating basic and diluted net income per common share.

The following is a reconciliation of the weighted average shares used in the basic and diluted net income per common share calculations for the periods indicated:

	Year Ended December 31,		
In thousands	2014	2013	2012
Basic weighted average common shares outstanding	348,962	366,659	385,205
Potentially dilutive securities			
Restricted stock, stock options, SARs and performance-based equity awards	2,205	3,218	3,733
Diluted weighted average common shares outstanding	351,167	369,877	388,938

Basic weighted average common shares exclude shares of nonvested restricted stock. As these restricted shares vest, they will be included in the shares outstanding used to calculate basic net income per common share (although all non-performance-based restricted stock is issued and outstanding upon grant). For purposes of calculating diluted weighted average common shares, the nonvested restricted stock, stock options, SARs, and performance-based equity awards are included in the computation using the treasury stock method, with the deemed proceeds equal to the average unrecognized compensation during the period, the purchase price that the grantee will pay in the future for stock options, and any estimated future tax consequences recognized directly in equity. Stock options and SARs of 4.8 million, 3.6 million and 4.1 million shares for the years ended December 31, 2014, 2013 and 2012, respectively, could potentially dilute earnings per share in the future, but were excluded from the computation of diluted net income per share as their effect would have been antidilutive.

Environmental and Litigation Contingencies

The Company makes judgments and estimates in recording liabilities for contingencies such as environmental remediation or ongoing litigation. Liabilities are recorded when it is both probable that a loss has been incurred and such loss is reasonably estimable. Assessments of liabilities are based on information obtained from independent and in-house experts, loss experience in similar situations, actual costs incurred, and other case-by-case factors. Any related insurance recoveries are recognized in our financial statements during the period received or at the time receipt is determined to be virtually certain.

Recent Accounting Pronouncements

Revenue Recognition. In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-09, *Revenue from Contracts with Customers* ("ASU 2014-09"). ASU 2014-09 amends the guidance for revenue recognition to replace numerous, industry-specific requirements. The core principle of the ASU is that an entity should recognize revenue for the transfer of goods or services equal to the amount that it expects to be entitled to receive for those goods or services. The ASU implements a five-step process for customer contract revenue recognition that focuses on transfer of control, as opposed to transfer of risk and rewards. The amendment also requires enhanced disclosures regarding the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. The amendments in this ASU are effective for reporting periods beginning after December 15, 2016, and early adoption is prohibited. Entities can transition to the standard either retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. Management is currently assessing the impact the adoption of ASU 2014-09 will have on our consolidated financial statements.

Discontinued Operations. In April 2014, the FASB issued ASU 2014-08, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity* ("ASU 2014-08"). ASU 2014-08 amends the definition of a discontinued operation under the *Discontinued Operations* subtopic of the FASC and requires entities to disclose additional information about discontinued operations and disposal transactions that do not meet the discontinued operations criteria. ASU 2014-08 will be applied prospectively for disposals of components of an entity and businesses or nonprofit activities that meet the criteria to be classified as held for sale and occur within annual periods beginning on or after December 15, 2014, and interim periods within those years. The adoption of ASU 2014-08 is currently not expected to have a material effect on our consolidated financial statements.

Note 2. Acquisition

Fair Value

The FASC *Fair Value Measurement* topic defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (often referred to as the "exit price"). The fair value measurement is based on the assumptions of market participants and not those of the reporting entity. Therefore, entity-specific intentions do not impact the measurement of fair value unless those assumptions are consistent with market participant views.

The fair value of oil and natural gas properties is based on significant inputs not observable in the market, which the FASC *Fair Value Measurement* topic defines as Level 3 inputs. Key assumptions may include (1) NYMEX oil and natural gas futures prices (this input is observable); (2) dollar-per-acre values of recent sale transactions (this input is observable); (3) projections of the estimated quantities of oil and natural gas reserves, including those classified as proved, probable and possible; (4) estimated oil and natural gas pricing differentials; (5) projections of future rates of production; (6) timing and amount of future development and operating costs; (7) projected costs of CO_2 (to a market participant); (8) projected reserve recovery factors; and (9) risk-adjusted discount rates.

2013 Acquisition

On March 27, 2013, we acquired producing assets in the Cedar Creek Anticline ("CCA") of Montana and North Dakota from a wholly-owned subsidiary of ConocoPhillips for $1.0 billion after final closing adjustments. This acquisition was not reflected as an Investing Activity on our Consolidated Statement of Cash Flows for the year ended December 31, 2013 due to the movement of the cash used to acquire these assets through a qualified intermediary to facilitate a like-kind-exchange treatment under federal income tax rules. This acquisition meets the definition of a business under the FASC *Business Combinations* topic. The fair value of assets acquired and liabilities assumed in this acquisition have been finalized, and no adjustments have been made to fair value amounts previously disclosed in our financial statements for the year ended December 31, 2013. The following table presents a summary of the fair value of assets acquired and liabilities assumed in the CCA acquisition:

In thousands	
Consideration	
Cash consideration [1]	$1,001,707
Fair value of assets acquired and liabilities assumed	
Oil and natural gas properties	
Proved properties	783,507
Unevaluated properties	222,820
Other assets	2,589
Asset retirement obligations	(7,209)
	$1,001,707

(1) See Note 6, *Income Taxes,* for additional information regarding the like-kind-exchange transaction utilized to fund this purchase and Note 13, *Supplemental Cash Flow Information*, for supplemental cash flow information regarding the cash payment.

For the period from March 27, 2013, to December 31, 2013, we recognized $268.3 million of oil, natural gas, and related product sales from the property interests acquired in the CCA acquisition; during that same period, we recognized $194.2 million of net field operating income (defined as oil, natural gas, and related product sales less lease operating expenses, production and ad valorem taxes, and marketing expenses) related to the CCA acquisition.

Unaudited Pro Forma Acquisition Information. The following combined pro forma total revenues and other income and net income are presented as if the previously discussed CCA acquisition had occurred on January 1, 2013:

In thousands, except per-share data	Year Ended December 31, 2013
Pro forma total revenues and other income	$2,599,301
Pro forma net income	439,801
Pro forma net income per common share	
Basic	$ 1.20
Diluted	1.19

Note 3. Asset Retirement Obligations

The following table summarizes the changes in our asset retirement obligations for the years ended December 31, 2014 and 2013:

	Year Ended December 31,	
In thousands	2014	2013
Beginning asset retirement obligations	$126,301	$106,430
Liabilities incurred and assumed during period	7,798	22,216
Revisions in estimated retirement obligations	(1,298)	4,730
Liabilities settled and sold during period	(13,576)	(15,523)
Accretion expense	8,870	8,448
Ending asset retirement obligations	128,095	126,301
Less: current asset retirement obligations (1)	(1,684)	(6,413)
Long-term asset retirement obligations	$126,411	$119,888

(1) Included in “Accounts payable and accrued liabilities” in our Consolidated Balance Sheets.

Liabilities incurred during 2014 and 2013 generally relate to the drilling of incremental wells, and liabilities assumed during 2013 include the purchase of additional interests in the CCA.

We have escrow accounts that are legally restricted for certain of our asset retirement obligations. The balances of these escrow accounts were $37.1 million and $36.0 million at December 31, 2014 and 2013, respectively. These balances are primarily invested in U.S. Treasury bonds, are recorded at amortized cost and are included in “Other assets” in our Consolidated Balance Sheets. The carrying value of these investments approximates their estimated fair market value at December 31, 2014 and 2013.

Note 4. Property and Equipment

The following table presents a summary of our net property and equipment balances as of December 31, 2014 and 2013:

	Year Ended December 31,	
In thousands	2014	2013
Oil and natural gas properties		
Proved properties	$ 9,782,337	$ 8,945,326
Unevaluated properties	918,406	780,481
Total	10,700,743	9,725,807
Accumulated depletion and depreciation	(3,679,883)	(3,219,500)
Net oil and natural gas properties	7,020,860	6,506,307
CO_2 properties		
CO_2 properties	1,162,538	1,117,167
Accumulated depletion and depreciation	(183,646)	(150,968)
Net CO_2 properties	978,892	966,199
Pipelines and plants		
CO_2 pipelines (1)	1,733,562	1,681,774
Plants	536,002	527,786
Total	2,269,564	2,209,560
Accumulated depletion and depreciation	(182,385)	(134,697)
Net plants and pipelines	2,087,179	2,074,863
Other property and equipment		
Other property and equipment	468,051	466,969
Accumulated depletion and depreciation	(202,738)	(163,060)
Net other property and equipment	265,313	303,909
Net property and equipment	$10,352,244	$ 9,851,278

(1) Amount includes $98.5 million of CO_2 pipelines at December 31, 2014 that were under construction and not subject to depreciation during 2014.

A summary of the unevaluated property costs excluded from oil and natural gas properties being amortized at December 31, 2014, and the year in which the costs were incurred follows:

	December 31, 2014				
	Costs Incurred During:				
In thousands	2014	2013	2012	2011 and Prior	Total
Property acquisition costs	$ 6,500	$215,822	$102,377	$329,840	$654,539
Exploration and development	125,783	40,835	22,080	10,361	199,059
Capitalized interest	21,807	24,898	12,084	6,019	64,808
Total	$154,090	$281,555	$136,541	$346,220	$918,406

Our 2013 property acquisition costs were primarily related to the fair value allocated to the purchase of additional interests in the CCA. Our 2012 property acquisition costs were primarily related to the fair value allocated to our Hartzog Draw and Thompson fields. Property acquisition costs for 2011 and prior were primarily related to the fair value allocated to CO_2 tertiary potential at our CCA properties, acquired as part of the merger with Encore Acquisition Company ("Encore"), as well as CO_2 tertiary potential at Conroe Field. Exploration and development costs shown as unevaluated properties are primarily associated with our tertiary oil fields that are under development but did not have proved reserves at December 31, 2014. The most significant development costs incurred during 2014 relate to development in preparation for the CO_2 floods at Webster and Grieve fields, with the more significant development costs incurred during 2013, 2012 and 2011 relating to development in preparation for the CO_2 flood at Grieve field. We have not yet recognized proved reserves in these fields.

Costs are transferred into the amortization base on an ongoing basis as projects are evaluated and proved reserves established or impairment determined. We review the excluded properties for impairment at least annually. We currently estimate that evaluation of the majority of these properties and the inclusion of their costs in the amortization base is expected to be completed within five to ten years. Until we are able to determine whether there are any proved reserves attributable to the above costs, we are not able to assess the future impact on the amortization rate of the full cost pool.

Note 5. Long-Term Debt

The following long-term debt and capital lease obligations were outstanding as of December 31, 2014 and 2013:

	December 31,	
In thousands	2014	2013
Bank Credit Agreement	$ 395,000	$ 340,000
8¼% Senior Subordinated Notes due 2020	—	996,273
6⅜% Senior Subordinated Notes due 2021	400,000	400,000
5½% Senior Subordinated Notes due 2022	1,250,000	—
4⅝% Senior Subordinated Notes due 2023	1,200,000	1,200,000
Other Senior Subordinated Notes, including premium of $11 and $16, respectively	2,746	3,823
Pipeline financings	220,583	228,167
Capital lease obligations	103,041	128,519
Total	3,571,370	3,296,782
Less: current obligations	(35,470)	(36,157)
Long-term debt and capital lease obligations	$3,535,900	$3,260,625

The ultimate parent company in our corporate structure, Denbury Resources Inc. ("DRI"), is the sole issuer of all of our outstanding senior subordinated notes. DRI has no independent assets or operations. Each of the subsidiary guarantors of such notes is 100% owned, directly or indirectly, by DRI, and the guarantees of such notes are full and unconditional and joint and several; any subsidiaries of DRI that are not subsidiary guarantors of such notes are minor subsidiaries.

Bank Credit Facility

In December 2014, we entered into an Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A. ("JPMorgan"), as administrative agent, and other lenders party thereto (the "Bank Credit Agreement") to replace our previous credit agreement that was set to mature in May 2016 (the "Previous Bank Credit Agreement"). The Bank Credit Agreement is a senior secured revolving credit facility with an initial borrowing base of $3.0 billion and aggregate lender commitments of $1.6 billion, and reduces our borrowing costs on the drawn spread. The $1.6 billion of aggregate lender commitments is consistent with the Previous Bank Credit Agreement and may be increased up to the borrowing base amount with approval and incremental commitments from the existing lenders or new lenders. Additionally, under the Bank Credit Agreement, letters of credit are available in an aggregate amount not to exceed $50 million, and short-term swingline loans are available in an aggregate amount not to exceed $25 million, each subject to the available commitments under the Bank Credit Agreement. Availability under the Bank Credit Agreement is subject to a borrowing base, which is redetermined annually beginning May 1, 2015. The borrowing base is adjusted at the lenders' discretion and is based, in part, upon external factors over which we have no control (including approval by the lenders party to the Bank Credit Agreement). The lenders may also reduce the borrowing base if between scheduled annual redeterminations we sell borrowing base properties and/or cancel commodity derivative positions with an aggregate value in excess of 10% of the then-effective borrowing base. If our outstanding debt under the Bank Credit Agreement exceeds the then-effective borrowing base, we would be required to repay the excess amount over a period not to exceed six months. Loans under the Bank Credit Agreement mature in December 2019.

Our obligations under the Bank Credit Agreement are guaranteed jointly and severally by each subsidiary of DRI that is 100% owned, directly or indirectly, by DRI. In addition, the Bank Credit Agreement is secured by (1) a significant portion of our proved oil and natural gas properties, which are held through its restricted subsidiaries; (2) the pledge of equity interests of such subsidiaries; and (3) a pledge of commodity derivative agreements of DRI and such subsidiaries (as applicable).

The Bank Credit Agreement contains several restrictive covenants including, among others:

- a requirement to maintain a maximum permitted ratio of consolidated total net debt to consolidated EBITDAX (as defined in the Bank Credit Agreement) of DRI and its wholly-owned subsidiaries of not more than 4.25 to 1.0;
- a requirement to maintain a current ratio, as determined under the Bank Credit Agreement, of not less than 1.0 to 1.0; and
- a limit on our ability to, among other things, incur indebtedness; grant liens; engage in certain mergers, consolidations, liquidations and dissolutions; engage in sales of assets; make acquisitions and investments; make distributions and dividends; and enter into commodity derivative agreements, in each case subject to customary exceptions.

As of December 31, 2014, we were in compliance with all debt covenants under the Bank Credit Agreement. Under the Bank Credit Agreement, we are permitted to make unlimited distributions in the form of repurchases of Denbury common stock and payments of cash dividends on Denbury common stock, provided that (1) prior to and after making any such distribution, no event of default exists and (2) we have minimum availability of at least 10% of the "loan limit" under the Bank Credit Agreement (currently the aggregate lender commitments of $1.6 billion) on the date such distribution is made (calculated on a pro forma basis after giving effect to the making of any such distribution).

Loans under the Bank Credit Agreement are subject to varying rates of interest based on either (1) for ABR Loans, a base rate determined under the Bank Credit Agreement (the "ABR") plus an applicable margin ranging from 0.25% to 1.25% per annum, or (2) for LIBOR Loans, the LIBOR rate plus an applicable margin ranging from 1.25% to 2.25% per annum (capitalized terms as defined in the Bank Credit Agreement). The weighted average interest rate on borrowings outstanding as of December 31, 2014 under the Bank Credit Agreement was 1.9%. The undrawn portion of the aggregate lender commitments under the Bank Credit Agreement is subject to a commitment fee ranging from 0.3% to 0.375% per annum.

Senior Subordinated Notes

2014 Repurchase and Redemption of 8¼% Senior Subordinated Notes due 2020. On April 30, 2014, we completed a cash tender offer for our 8¼% Senior Subordinated Notes due 2020 (the "8¼% Notes") and purchased a total of $815.2 million principal amount of these notes. We received sufficient consents in the solicitation to amend the indenture governing the 8¼% Notes by entering into a supplemental indenture, which eliminated most of the restrictive covenants and certain events of default. The purchase under this tender offer was funded by a portion of the proceeds from the issuance of our 5½% Notes (defined below). On April 30, 2014, we issued a notice of redemption and fully funded the redemption of all of the remaining outstanding 8¼% Notes ($181.1 million principal amount) at an amount equal to 100% of their principal amount plus the required make-whole premium and accrued interest up to, but excluding, the May 30, 2014, redemption date, resulting in a satisfaction and discharge of the indenture for the 8¼% Notes.

We recognized a $113.9 million loss associated with the debt repurchases during the second quarter of 2014, which loss consists of both premium payments made to repurchase or redeem the 8¼% Notes and the elimination of unamortized debt issuance costs related to these notes. The loss is included in our Consolidated Statements of Operations under the caption "Loss on early extinguishment of debt," and premium payments made to repurchase the notes are classified as a financing cash outflow on our Consolidated Statements of Cash Flows under the caption "Premium paid on repayment of senior subordinated notes."

6⅜% Senior Subordinated Notes due 2021. In February 2011, we issued $400 million of 6⅜% Senior Subordinated Notes due 2021 (the "6⅜% Notes"). The 6⅜% Notes, which bear interest at a rate of 6.375% per annum, were sold at par.

The 6⅜% Notes mature on August 15, 2021, and interest is payable on February 15 and August 15 of each year. We may redeem the 6⅜% Notes in whole or in part at our option beginning August 15, 2016, at a redemption price of 103.188% of the principal amount, and at declining redemption prices thereafter, as specified in the indenture. Prior to August 15, 2016, we may redeem 100% of the principal amount of the 6⅜% Notes at a price equal to 100% of the principal amount plus a "make-whole" premium and accrued and unpaid interest. The 6⅜% Notes are not subject to any sinking fund requirements.

5½% Senior Subordinated Notes due 2022. In April 2014, we issued $1.25 billion of 5½% Senior Subordinated Notes due 2022 (the "5½% Notes"). The 5½% Notes, which bear interest at a rate of 5.5% per annum, were sold at par. The net proceeds, after issuance costs, of $1.23 billion were used to repurchase or redeem our outstanding 8¼% Notes, which were issued in 2010 (see *2014 Repurchase and Redemption of 8¼% Senior Subordinated Notes due 2020* above), and to pay down a portion of outstanding borrowings under our Previous Bank Credit Agreement.

The 5½% Notes mature on May 1, 2022, and interest is payable on May 1 and November 1 of each year. We may redeem the 5½% Notes in whole or in part at our option beginning May 1, 2017, at a redemption price of 104.125% of the principal amount, and at declining redemption prices thereafter, as specified in the indenture. Prior to May 1, 2017, we may at our option redeem up to an aggregate of 35% of the principal amount of the 5½% Notes at a price of 105.5% of par with the proceeds of certain equity offerings. In addition, at any time prior to May 1, 2017, we may redeem 100% of the principal amount of the 5½% Notes at a price equal to 100% of the principal amounts plus a "make-whole" premium and accrued and unpaid interest. The 5½% Notes are not subject to any sinking fund requirements.

4⅝% Senior Subordinated Notes due 2023. In February 2013, we issued $1.2 billion of 4⅝% Senior Subordinated Notes due 2023 (the "4⅝% Notes"). The 4⅝% Notes, which bear interest at a rate of 4.625% per annum, were sold at par. The net proceeds, after issuance costs, of $1.18 billion were used to repurchase or redeem our 9½% Senior Subordinated Notes due 2016 (the "9½% Notes") and 9¾% Senior Subordinated Notes due 2016 (the "9¾% Notes") (see *2013 Repurchase and Redemption of 9½% Notes and 9¾% Notes* below) and to pay down a portion of outstanding borrowings under our Previous Bank Credit Agreement.

The 4⅝% Notes mature on July 15, 2023, and interest is payable on January 15 and July 15 of each year. We may redeem the 4⅝% Notes in whole or in part at our option beginning January 15, 2018, at a redemption price of 102.313% of the principal amount, and at declining redemption prices thereafter, as specified in the indenture. Prior to January 15, 2016, we may at our option redeem up to an aggregate of 35% of the principal amount of the 4⅝% Notes at a redemption price of 104.625% of par with the proceeds of certain equity offerings. In addition, at any time prior to January 15, 2018, we may redeem 100% of the principal amount of the 4⅝% Notes at a redemption price equal to 100% of the principal amount plus a "make-whole" premium and accrued and unpaid interest. The 4⅝% Notes are not subject to any sinking fund requirements.

Restrictive Covenants in Indentures for Senior Subordinated Notes. Each of the indentures for the 6⅜% Notes, 5½% Notes and 4⅝% Notes contains certain covenants that are generally consistent and that restrict our ability and the ability of our restricted subsidiaries to take or permit certain actions, including restrictions on our ability and the ability of our restricted subsidiaries to (1) incur additional debt; (2) make investments; (3) create liens on our assets or the assets of our restricted subsidiaries; (4) create restrictions on the ability of our restricted subsidiaries to pay dividends or make other payments to DRI or other restricted subsidiaries; (5) engage in transactions with our affiliates; (6) transfer or sell assets or subsidiary stock; (7) consolidate, merge or transfer all or substantially all of our assets and the assets of our restricted subsidiaries; and (8) make restricted payments (which includes paying dividends on our common stock or redeeming, repurchasing or retiring such stock or subordinated debt), provided that the restricted payments covenant in the indentures for the 5½% and 4⅝% Notes (the "5½% and 4⅝% Indentures") permits us in certain circumstances to make unlimited restricted payments so long as we maintain a ratio of total debt to EBITDA (both as defined in the 5½% and 4⅝% Indentures) of at least 2.5 to 1.0 (both before and after giving effect to any restricted payment), although we will not be able to realize the practical benefit of the restricted payment covenant flexibility in the 5½% and 4⅝% Indentures until the 6⅜% Notes have been redeemed or retired. As of December 31, 2014, we were in compliance with all debt covenants under the indentures related to our senior subordinated notes.

2013 Repurchase and Redemption of 9½% Notes and 9¾% Notes. Pursuant to cash tender offers, during 2013, we repurchased $426.4 million in principal of our 9¾% Notes and $224.9 million in principal of our 9½% Notes. We recognized a $44.7 million loss during the year ended December 31, 2013, associated with the debt repurchases, consisting of both premium payments made to repurchase or redeem the 9½% Notes and 9¾% Notes and the elimination of unamortized debt issuance costs, discounts and premiums related to these notes. The loss is included in our Consolidated Statements of Operations under the caption "Loss on early extinguishment of debt," and premium payments made to repurchase the notes are classified as a financing cash outflow on our Consolidated Statements of Cash Flows under the caption "Premium paid on repayment of senior subordinated notes."

Pipeline Financings

In May 2008, we closed two transactions with Genesis Energy, L.P. ("Genesis") involving two of our pipelines. The NEJD Pipeline system included a 20-year financing lease, and the Free State Pipeline included a long-term transportation service agreement. These transactions are both accounted for as financing leases.

Debt Issuance Costs

In connection with the issuance of our outstanding long-term debt, we have incurred debt issuance costs, which are being amortized to interest expense using the straight line or effective interest method over the term of each related facility or borrowing. Remaining unamortized debt issuance costs were $57.3 million and $58.9 million at December 31, 2014 and 2013, respectively. These balances are included in "Other assets" in our Consolidated Balance Sheets.

Indebtedness Repayment Schedule

At December 31, 2014, our indebtedness, including our capital and financing lease obligations but excluding the discount and premium on our senior subordinated debt, is payable over the next five years and thereafter as follows:

In thousands	
2015	$ 35,470
2016	38,517
2017	37,087
2018	33,885
2019	422,879
Thereafter	3,003,521
Total indebtedness	$3,571,359

Note 6. Income Taxes

Our income tax provision (benefit) is as follows:

	Year Ended December 31,		
In thousands	2014	2013	2012
Current income tax expense (benefit)			
Federal	$ (42,500)	$ 393	$ 57,720
State	(407)	9,864	18,034
Total current income tax expense (benefit)	(42,907)	10,257	75,754
Deferred income tax expense (benefit)			
Federal	400,544	222,559	239,862
State	29,429	(33)	15,881
Total deferred income tax expense	429,973	222,526	255,743
Total income tax expense	$387,066	$232,783	$331,497

At December 31, 2014, we had tax-effected federal net operating loss carryforwards ("NOLs") totaling $44.1 million, state NOLs totaling $43.3 million, an estimated $42.8 million of enhanced oil recovery credits to carry forward related to our tertiary operations, and $34.8 million of alternative minimum tax credits. Our state NOLs expire in various years, starting in 2020, although most do not begin to expire until 2024. Our enhanced oil recovery credits will begin to expire in 2024.

At December 31, 2014, we had $13.5 million of excess tax benefits related to stock-based compensation that were not recorded as an increase to additional paid-in capital in the period that the stock award vested and/or was exercised. At the time these excess tax benefits reduce current taxes payable and, thus, are deemed to be realized by the Company, a corresponding increase to additional paid-in capital will be recognized.

Deferred income taxes reflect the available tax carryforwards and the temporary differences based on tax laws and statutory rates in effect at the December 31, 2014 and 2013 balance sheet dates. We believe that we will be able to realize all of our deferred tax assets at December 31, 2014, and, therefore, have provided no valuation allowance against our deferred tax assets.

For federal income tax purposes, we structured the 2012 divestitures of our Bakken area assets and certain non-core assets as like-kind-exchange transactions for interests acquired in Thompson, Webster, Hartzog Draw and LaBarge fields in 2012 and the CCA acquisition in 2013 (see Note 2, *Acquisition*), thereby deferring the majority of the taxable gain on those divestitures. The higher level of current taxes during 2012 is primarily due to the taxable gain recognized in the late-2012 sale and exchange transaction with Exxon Mobil Corporation and its wholly-owned subsidiary XTO Energy Inc. (the "Bakken Exchange Transaction") that we were unable to defer through a like-kind-exchange transaction.

Significant components of our deferred tax assets and liabilities as of December 31, 2014 and 2013 are as follows:

	December 31,	
In thousands	2014	2013
Deferred tax assets		
Loss carryforwards – federal	$ 44,076	$ 20,247
Loss carryforwards – state	43,270	41,379
Tax credit carryover	34,837	34,837
Derivative contracts	—	21,341
Enhanced oil recovery credit carryforwards	42,817	14,974
Stock-based compensation	29,994	34,635
Other	32,656	37,679
Total deferred tax assets	227,650	205,092
Deferred tax liabilities		
Property and equipment	(2,806,850)	(2,541,426)
Derivative contracts	(185,385)	—
Other	(11,984)	(10,206)
Total deferred tax liabilities	(3,004,219)	(2,551,632)
Total net deferred tax liability	$(2,776,569)	$(2,346,540)

Our reconciliation of income tax expense computed by applying the U.S. federal statutory rate and the reported effective tax rate on income from continuing operations is as follows:

	Year Ended December 31,		
In thousands	2014	2013	2012
Income tax provision calculated using the federal statutory income tax rate	$357,895	$224,833	$299,900
State income taxes, net of federal income tax benefit	25,368	13,518	30,955
Effect of statutory rate change	4,225	(4,178)	(429)
Other	(422)	(1,390)	1,071
Total income tax expense	$387,066	$232,783	$331,497

We file consolidated and separate income tax returns in the U.S. federal jurisdiction and in many state jurisdictions. The statutes of limitation for our income tax returns for tax years ending prior to 2011 have lapsed and therefore are not available for examination by respective taxing authorities. We have not paid any significant interest or penalties associated with our income taxes.

Note 7. Stockholders' Equity

Dividends

During 2014, we paid aggregate cash dividends of $87.0 million to holders of our outstanding common stock at a quarterly rate of $0.0625 per outstanding common share, or an annual rate of $0.25 per common share. See Note 14, *Subsequent Events,* for details regarding the dividend declared in the first quarter of 2015.

Stock Repurchase Program

In October 2011, we commenced a common share repurchase program for up to $500 million of Denbury common shares, as approved by the Company's Board of Directors. During 2012 and 2013, the Board of Directors increased the dollar amount of Denbury common shares that could be purchased under the program to an aggregate of up to $1.162 billion. The program has no pre-established ending date and may be suspended or discontinued at any time. In November 2014, the Company's Board of Directors suspended the common share repurchase program in light of commodity price uncertainty and to maintain our solid financial position. We are not obligated to repurchase any dollar amount or specific number of shares of our common stock under the program. The following table presents a summary of repurchases under our share repurchase program:

In thousands, except per-share data	Total Repurchases Since Inception	Year Ended December 31, 2014	2013	2012
Total amount repurchased	$940,021	$200,369	$277,768	$266,657
Weighted average price per share	$ 15.68	$ 16.16	$ 16.87	$ 15.71
Denbury common stock repurchased (shares)	59,957	12,398	16,469	16,978

As of December 31, 2014, an additional $221.9 million remains authorized for purchases of common stock under this repurchase program (but subject to the current suspension of this program by the Company's Board of Directors in November 2014). We account for treasury stock using the cost method and include treasury stock as a component of stockholders' equity.

Employee Stock Purchase Plan

We have an Employee Stock Purchase Plan that is authorized to issue up to 11,900,000 shares of common stock. As of December 31, 2014, there were 354,074 authorized shares remaining to be issued under the plan. We intend to increase the number of shares authorized for issuance under this plan, subject to shareholder approval at our 2015 annual meeting. In accordance with the plan, eligible employees may contribute up to 10% of their base salary, and we match 75% of their contribution. The combined funds are used to purchase previously unissued Denbury common stock or treasury stock that we purchased in the open market for that purpose, in either case, based on the market value of our common stock at the end of each quarter. We recognize compensation expense for the Company match portion, which totaled $7.0 million, $6.5 million and $5.7 million for the years ended December 31, 2014, 2013 and 2012, respectively. This plan is administered by the Compensation Committee of our Board of Directors.

401(k) Plan

We offer a 401(k) plan to which employees may contribute tax-deferred earnings subject to IRS limitations. We match 100% of an employee's contribution, up to 6% of compensation, as defined by the plan, which is vested immediately. During 2014, 2013 and 2012, our matching contributions to the 401(k) Plan were approximately $9.9 million, $9.0 million and $8.0 million, respectively.

Note 8. Stock Compensation Plans

Stock Incentive Plans

We have two stock compensation plans. The first plan (providing only for the issuance of stock options) has been in existence since 1995 (the "1995 Plan") and expired in August 2005 (although options granted under the 1995 Plan prior to that time can remain outstanding for up to 10 years). The second plan, the 2004 Omnibus Stock and Incentive Plan (the "2004 Plan"), was approved by the stockholders in May 2004 and will expire in May 2024. The 2004 Plan provides for the issuance of incentive and non-qualified stock options, restricted stock awards, restricted stock units, SARs settled in stock, and performance-based awards that may be issued to officers, employees, directors and consultants. Awards covering a total of 34.5 million shares of common stock have been authorized for issuance pursuant to the 2004 Plan, of which awards covering no more than 27.2 million shares may be issued in the form of restricted stock or performance-based awards. At December 31, 2014, 9.7 million shares were available under the 2004 Plan for future issuance of awards, all of which could be issued in the form of restricted stock or performance-based awards. Our incentive compensation program is administered by the Compensation Committee of our Board of Directors.

Prior to January 1, 2006, we granted incentive and non-qualified stock options to our employees. Effective January 1, 2006, we completely replaced the use of stock options for employees with SARs settled in stock, as SARs are less dilutive to our stockholders while providing an employee with essentially the same economic benefits as stock options. The stock options and SARs generally become exercisable over a three- or four-year vesting period, with the specific terms of vesting determined at the time of grant based on guidelines established by the Compensation Committee of the Board of Directors. The stock options and SARs expire over terms not to exceed 10 years from the date of grant, 90 days after termination of employment, 90 days or one year after permanent disability, depending on the plan, or one year after the death of the optionee. The stock options and SARs are granted with a strike price equal to the fair market value at the time of grant, which is defined in the 2004 Plan as the closing price on the NYSE on the date of grant.

Holders of non-performance-based restricted stock awards have the rights and privileges of owning the shares (including voting rights) except that the holders are not entitled to delivery of a portion thereof until certain requirements are met. Beginning in 2014, non-performance-based restricted stock awards granted by the Company provide the holders with forfeitable dividend rights until the award vests. Non-performance-based restricted stock awards vest over three-to-four-year vesting periods, with the specific terms of vesting determined at the time of grant.

Annually, the Board of Directors grants performance-based equity awards to officers of Denbury. These performance-based awards generally vest over 1.25 to 3.25 years, and the number of performance-based shares earned (and eligible to vest) during the performance period will depend upon two sets of factors: (1) our level of success in achieving specifically identified performance targets ("Performance-Based Operational Awards") and (2) performance of our stock relative to that of a designated peer group ("Performance-Based TSR Awards"). Generally, one-half of the maximum number of shares that could be earned under the performance-based awards will be earned for performance at the designated target levels (100% target vesting levels) or upon any earlier change of control, and twice the target number of shares will be earned if the maximum target levels are met. If performance is below the designated minimum levels for all performance targets, no performance-based shares will be earned. Performance-Based Operational Awards are valued using the fair market value of Denbury stock on the grant date, and Performance-Based TSR Awards are valued using a Monte Carlo simulation.

Stock-based compensation expense associated with our field employees is included in "Lease operating expenses," while such expense associated with non-field employees is included in "General and administrative expenses" in the Consolidated Statements of Operations. Stock-based compensation associated with our employees involved in exploration and drilling activities is capitalized as part of "Oil and natural gas properties" in the Consolidated Balance Sheets.

Stock-based compensation costs for the years ended December 31, 2014, 2013 and 2012, are as follows:

	Year Ended December 31,		
In thousands	2014	2013	2012
Stock-based compensation expensed			
General and administrative expenses	$27,789	$30,429	$26,463
Lease operating expenses	2,724	2,574	2,847
Total stock-based compensation expensed	30,513	33,003	29,310
Stock-based compensation capitalized	9,019	9,088	8,587
Total cost of stock-based compensation arrangements	$39,532	$42,091	$37,897
Income tax benefit recognized for stock-based compensation arrangements	$11,595	$12,541	$11,284

Stock Options and SARs

The fair value of each SAR award is estimated on the date of grant using the Black-Scholes option pricing model with the assumptions noted in the following table. The risk-free rate for periods within the contractual life of the SAR is based on the U.S. Treasury yield curve in effect at the time of grant. The expected life of SARs granted was derived from examination of our historical SAR grants and subsequent exercises. The contractual terms (cliff vesting and graded vesting) are evaluated separately for the expected life, as the exercise behavior for each is different. Expected volatilities are based on the historical volatility of our common stock.

	Year Ended December 31,		
	2014	2013	2012
Weighted average fair value of SARs granted	$3.55	$6.72	$8.90
Risk-free interest rate	1.31%	0.67%	0.79%
Expected life	3.8 to 4.0 years	3.6 to 4.8 years	4.0 to 5.0 years
Expected volatility	38.0%	50.4%	64.9%
Dividend yield	3.10%	—%	—%

The following is a summary of our stock option and SAR activity:

	Number of Awards	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at December 31, 2013	8,986,915	$16.00		
Granted	555,786	14.60		
Exercised	(1,612,822)	10.23		
Forfeited	(136,493)	17.03		
Expired	(324,653)	21.02		
Outstanding at December 31, 2014	7,468,733	16.90	2.8	$178
Exercisable at end of period	5,846,933	$17.05	2.2	$ 74

The following is a summary of the total intrinsic value of stock options and SARs exercised and grant-date fair value of stock options and SARs vested:

	Year Ended December 31,		
In thousands	2014	2013	2012
Intrinsic value of stock options and SARs exercised	$7,985	$17,287	$17,315
Grant-date fair value of stock options and SARs vested	9,998	12,852	26,391

As of December 31, 2014, there was $3.5 million of total compensation cost to be recognized in future periods related to nonvested share-based SAR compensation arrangements. The cost is expected to be recognized over a weighted-average period of 1.6 years. The following is a summary of cash received from stock option exercises under share-based payment arrangements and tax benefits realized from the exercises of stock options and SARs:

	Year Ended December 31,		
In thousands	2014	2013	2012
Cash received from stock option exercises	$ 7,022	$5,487	$ 6,022
Tax benefit realized for the exercises of stock options and SARs	212	437	458

Restricted Stock – 2004 Plan

As of December 31, 2014, there was $27.7 million of unrecognized compensation expense related to nonvested non-performance-based restricted stock grants. This unrecognized compensation cost is expected to be recognized over a weighted-average period of 1.8 years. The following is a summary of the total vesting date fair value of non-performance-based restricted stock under the 2004 Plan:

	Year Ended December 31,		
In thousands	2014	2013	2012
Fair value of restricted stock vested	$24,780	$21,529	$22,332

A summary of the status of our nonvested non-performance-based restricted stock grants issued under our 2004 Plan and the changes during the year ended December 31, 2014, is presented below:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at December 31, 2013	3,761,084	$ 15.98
Granted	2,001,148	16.34
Vested	(1,512,407)	16.91
Forfeited	(510,791)	13.27
Nonvested at December 31, 2014	3,739,034	16.17

Restricted Stock – Legacy Encore Plan

In February 2010, prior to the consummation of the merger with Encore, Encore issued a restricted stock grant to its employees under the Encore Acquisition Company 2008 Incentive Stock Plan ("Encore Plan"). At the time of the merger with Encore, the shares were converted into shares of Denbury restricted stock. The shares vest ratably over a four-year graded vesting period; however, legacy Encore employees who terminated their employment for Good Reason, as defined by Encore's legacy Employee Severance Protection Plan, automatically vested in their awards upon termination. The remaining nonvested restricted stock issued under the Encore Plan vested during the first quarter of 2014. The following is a summary of the total vesting date fair value of restricted stock under the Encore Plan:

	Year Ended December 31,		
In thousands	2014	2013	2012
Fair value of restricted stock vested	$340	$512	$584

A summary of the status of the vested restricted stock grants under the Encore Plan and the changes during the year ended December 31, 2014, is presented below:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at December 31, 2013	21,741	$15.43
Vested	(21,078)	15.43
Forfeited	(663)	15.43
Nonvested at December 31, 2014	—	—

Performance-Based Equity Awards

During 2014 and 2013, we granted Performance-Based Operational Awards and Performance-Based TSR Awards to our officers. As of December 31, 2014, there was $5.3 million of unrecognized compensation expense related to nonvested performance-based equity awards. This unrecognized compensation cost is expected to be recognized over a weighted-average period of 1.9 years. The range of assumptions used in the Monte Carlo simulation valuation approach for Performance-Based TSR Awards (presented at the target level) are as follows:

	Year Ended December 31,		
	2014	2013	2012
Weighted average fair value of Performance-Based TSR Awards granted	$19.81	$20.08	$24.68
Risk-free interest rate	0.80%	0.41%	0.42%
Expected life	3.0 years	3.0 years	2.8 years
Expected volatility	39.4%	42.3%	45.2%
Dividend yield	2.50%	—%	—%

A summary of the status of the nonvested performance-based equity awards (presented at the target level) during the year ended December 31, 2014, is as follows:

	Performance-Based Operational Awards		Performance-Based TSR Awards	
	Number of Awards	Weighted Average Grant-Date Fair Value	Number of Awards	Weighted Average Grant-Date Fair Value
Nonvested at December 31, 2013	209,474	$16.77	296,391	$21.43
Granted	275,870	16.55	275,870	19.81
Forfeited	(33,946)	16.64	(38,650)	20.50
Nonvested at December 31, 2014	451,398	16.65	533,611	20.66

The following is a summary of the total vesting date fair value of performance-based equity awards:

	Year Ended December 31,		
In thousands	2014	2013	2012
Vesting date fair value of Performance-Based Operational Awards	$ —	$2,541	$2,191

Note 9. Commodity Derivative Contracts

We do not apply hedge accounting treatment to our oil and natural gas derivative contracts; therefore, the changes in the fair values of these instruments are recognized in income in the period of change. These fair value changes, along with the settlements of expired contracts, are shown under “Commodity derivatives expense (income)” in our Consolidated Statements of Operations.

From time to time, we enter into various oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production. We do not hold or issue derivative financial instruments for trading purposes. These contracts have historically consisted of price floors, collars, three-way collars, fixed-price swaps, and fixed-price swaps enhanced with a sold put. The production that we hedge has varied from year to year depending on our levels of debt and financial strength and expectation of future commodity prices. For the past several years, we have employed a strategy to hedge a substantial portion of our forecasted production approximately 18 months to two years in the future (from the then-current quarter), as we believe it is important to protect our future cash flow to provide a level of assurance for our capital spending and dividends in those future periods. With the decline in commodity futures prices in late 2014 and early 2015, as of late February 2015, we have deferred entering into new oil derivative contracts since the third quarter of 2014. Therefore, as of February 19, 2015, the percentage of our forecasted oil production that is currently hedged for the fourth quarter of 2015 and calendar 2016 is less than the percentage hedged in recent years. During periods of lower oil prices, we may defer entering into new contracts until futures prices return to levels that we consider economically conducive to our doing so.

We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures, and diversification, and all of our commodity derivative contracts are with parties that are lenders under our Bank Credit Agreement (or affiliates of such lenders). As of December 31, 2014, all of our outstanding derivative contracts were subject to enforceable master netting arrangements whereby payables on those contracts can be offset against receivables from separate derivative contracts with the same counterparty. It is our policy to classify derivative assets and liabilities on a gross basis on our balance sheets, even if the contracts are subject to enforceable master netting arrangements.

The following table summarizes our commodity derivative contracts, none of which are classified as hedging instruments in accordance with the FASC *Derivatives and Hedging* topic:

			Contract Prices[1]				
				Weighted Average Price			
Months	Index Price	Volume[2]	Range[3]	Swap	Sold Put	Floor	Ceiling
Oil Contracts:							
2015 Enhanced Swaps[4]							
Jan – Mar	NYMEX	14,000	$90.00 – 90.30	$90.06	$65.21	$ —	$ —
Jan – Mar	LLS	16,000	93.20 – 94.00	93.63	68.00	—	—
Apr – June	NYMEX	8,000	90.00 – 90.00	90.00	65.75	—	—
Apr – June	LLS	16,000	93.20 – 94.00	93.65	68.00	—	—
July – Sept	NYMEX	10,000	90.00 – 90.10	90.02	65.30	—	—
July – Sept	LLS	16,000	93.20 – 94.00	93.65	68.00	—	—
Oct – Dec	NYMEX	12,000	91.15 – 94.00	92.42	68.00	—	—
Oct – Dec	LLS	8,000	93.80 – 96.50	94.94	68.00	—	—
2015 Collars							
Jan – Mar	NYMEX	24,000	$80.00 – 100.90	$ —	$ —	$80.00	$ 96.75
Jan – Mar	LLS	4,000	85.00 – 102.20	—	—	85.00	102.10
Apr – June	NYMEX	30,000	80.00 – 95.25	—	—	80.00	94.72
Apr – June	LLS	4,000	85.00 – 102.50	—	—	85.00	101.75
July – Sept	NYMEX	28,000	80.00 – 95.25	—	—	80.00	95.05
July – Sept	LLS	4,000	85.00 – 100.00	—	—	85.00	99.50
2015 Three-Way Collars[5]							
Oct – Dec	NYMEX	10,000	$85.00 – 102.00	$ —	$68.00	$85.00	$ 99.00
Oct – Dec	LLS	8,000	88.00 – 104.25	—	68.00	88.00	100.99
2016 Enhanced Swaps[4]							
Jan – Mar	NYMEX	12,000	$90.65 – 93.35	$92.43	$68.00	$ —	$ —
Jan – Mar	LLS	8,000	93.70 – 95.45	94.81	68.50	—	—
Apr – June	NYMEX	2,000	90.35 – 90.35	90.35	68.00	—	—
Apr – June	LLS	6,000	93.30 – 93.50	93.38	70.00	—	—
2016 Three-Way Collars[5]							
Jan – Mar	NYMEX	10,000	$85.00 – 101.25	$ —	$68.00	$85.00	$ 99.85
Jan – Mar	LLS	6,000	88.00 – 103.15	—	68.00	88.00	102.10
Apr – June	NYMEX	2,000	85.00 – 95.50	—	68.00	85.00	95.50
Apr – June	LLS	2,000	88.00 – 98.25	—	70.00	88.00	98.25
Natural Gas Contracts:							
2015 Collars							
Jan – Dec	NYMEX	8,000	$ 4.00 – 4.53	$ —	$ —	$ 4.00	$ 4.51

(1) Contract prices are stated in $/Bbl and $/MMBtu for oil and natural gas contracts, respectively.

(2) Contract volumes are stated in Bbls/d and MMBtus/d for oil and natural gas contracts, respectively.

(3) Ranges presented for enhanced swaps represent the lowest and highest fixed prices of all open contracts for the period presented. For collars and three-way collars, ranges represent the lowest floor price and highest ceiling price for all open contracts for the period presented.

(4) An enhanced swap is a fixed-price swap contract combined with a sold put feature (at a lower price) with the same counterparty. The value associated with the sold put is used to increase or enhance the fixed price of the swap. At the contract settlement date, (1) if the index price is higher than the swap price, we pay the counterparty the difference between the index price and swap price for the contracted volumes, (2) if the index price is lower than the swap price but at or above the sold put price, the counterparty pays us the difference between the index price and the swap price for the contracted volumes, and (3) if the index price is lower than the sold put price, the counterparty pays us the difference between the swap price and the sold put price for the contracted volumes.

(5) A three-way collar is a costless collar contract combined with a sold put feature (at a lower price) with the same counterparty. The value received for the sold put is used to enhance the contracted floor and ceiling price of the related collar. At the contract settlement date, (1) if the index price is higher than the ceiling price, we pay the counterparty the difference between the index price and ceiling price for the contracted volumes, (2) if the index price is between the floor and ceiling price, no settlements occur, (3) if the index price is lower than the floor price but at or above the sold put price, the counterparty pays us the difference between the index price and the floor price for the contracted volumes, and (4) if the index price is lower than the sold put price, the counterparty pays us the difference between the floor price and the sold put price for the contracted volumes.

Note 10. Fair Value Measurements

The FASC *Fair Value Measurement* topic defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (often referred to as the "exit price"). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the income approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observability of those inputs. The FASC establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

- Level 1 — Quoted prices in active markets for identical assets or liabilities as of the reporting date.
- Level 2 — Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. Instruments in this category include non-exchange-traded oil and natural gas derivatives that are based on NYMEX pricing. Our costless collars and the sold put features of our enhanced oil swaps and three-way collars are valued using the Black-Scholes model, an industry standard option valuation model that takes into account inputs such as contractual prices for the underlying instruments, including maturity, quoted forward prices for commodities, interest rates, volatility factors and credit worthiness, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.
- Level 3 — Pricing inputs include significant inputs that are generally less observable. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. At December 31, 2014, instruments in this category include non-exchange-traded oil derivatives that are based on regional pricing other than NYMEX (e.g., Light Louisiana Sweet). The valuation models utilized for enhanced swaps, costless collars and three-way collars are consistent with the methodologies described above; however, since the instruments are based on regional pricing other than NYMEX, certain inputs to the valuation are less observable. Implied volatilities utilized in the valuation of Level 3 instruments are developed using a benchmark, which is considered a significant unobservable input. A one percent increase or decrease in implied volatility would result in a change of approximately $1.4 million in the fair value of these instruments as of December 31, 2014.

We adjust the valuations from the valuation model for nonperformance risk, using our estimate of the counterparty's credit quality for asset positions and our credit quality for liability positions. We use multiple sources of third-party credit data in determining counterparty nonperformance risk, including credit default swaps.

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2014 and 2013:

	Fair Value Measurements Using:			
In thousands	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
December 31, 2014				
Assets				
Oil and natural gas derivative contracts – current	$ —	$ 283,238	$ 157,121	$ 440,359
Oil and natural gas derivative contracts – long-term	—	34,862	31,325	66,187
Total Assets	$ —	$ 318,100	$ 188,446	$ 506,546
December 31, 2013				
Assets				
Oil and natural gas derivative contracts – current	$ —	$ 5	$ —	$ 5
Oil and natural gas derivative contracts – long-term	—	3,034	6,908	9,942
Total Assets	$ —	$ 3,039	$ 6,908	$ 9,947
Liabilities				
Oil and natural gas derivative contracts – current	$ —	$ (53,822)	$ —	$ (53,822)
Oil and natural gas derivative contracts – long-term	—	(3,214)	(199)	(3,413)
Total Liabilities	$ —	$ (57,036)	$ (199)	$ (57,235)

Since we do not apply hedge accounting for our commodity derivative contracts, any gains and losses on our assets and liabilities are included in “Commodity derivatives expense (income)” in the accompanying Consolidated Statements of Operations.

Level 3 Fair Value Measurements

The following table summarizes the changes in the fair value of our Level 3 assets and liabilities for the years ended December 31, 2014 and 2013:

In thousands	Year Ended December 31, 2014	2013
Fair value of Level 3 instruments, beginning of year	$ 6,709	$ —
Fair value adjustments on commodity derivatives	181,737	6,709
Fair value of Level 3 instruments, end of year	$188,446	$6,709
The amount of total gains for the period included in earnings attributable to the change in unrealized gains relating to assets still held at the reporting date	$181,737	$6,709

We utilize an income approach to value our Level 3 enhanced swaps, costless collars and three-way collars. We obtain and ensure the appropriateness of the significant inputs to the calculation, including contractual prices for the underlying instruments, maturity, forward prices for commodities, interest rates, volatility factors and credit worthiness, and the fair value estimate is prepared and reviewed on a quarterly basis. The following table details fair value inputs related to implied volatilities utilized in the valuation of our Level 3 oil derivative contracts:

	Fair Value at 12/31/2014 (in thousands)	Valuation Technique	Unobservable Input	Range
Oil derivative contracts	$ 188,446	Discounted cash flow/ Black-Scholes	Volatility of Light Louisiana Sweet for settlement periods beginning after January 1, 2015	29.3% – 44.2%

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

During 2012, we recorded a $15.1 million impairment charge for an investment in the preferred stock of an entity that was created to develop a gasification plant (in which we would offtake its CO_2 to use in our tertiary oil operations) as a result of this project not moving forward. This charge is classified as “Impairment of assets” in the Consolidated Statement of Operations for the year ended December 31, 2012.

Other Fair Value Measurements

The carrying value of our loans under our Bank Credit Agreement approximate fair value as they are subject to short-term floating interest rates that approximate the rates available to us for those periods. We use a market approach to determine fair value of our fixed-rate long-term debt using observable market data. The fair values of our senior subordinated notes are based on quoted market prices. The estimated fair value of our debt as of December 31, 2014 and 2013, excluding pipeline financing and capital lease obligations, is $2,938.6 million and $2,957.9 million, respectively. We have other financial instruments consisting primarily of cash, cash equivalents, short-term receivables and payables that approximate fair value due to the nature of the instrument and the relatively short maturities.

Note 11. Commitments and Contingencies

Leases

We lease office space, equipment and vehicles that have non-cancelable lease terms. Currently, our outstanding leases have terms up to 11 years. We have subleased part of the office space included in our operating leases for which we received rental payments. The following table summarizes operating lease payments paid and sublease rentals received during the periods indicated:

In thousands	Year Ended December 31, 2014	2013	2012
Operating lease payments	$43,333	$37,211	$33,606
Sublease rental receipts	2,347	2,237	2,685

The following tables summarize by year the remaining non-cancelable future payments under our leases as of December 31, 2014:

In thousands	Pipeline and Capital Leases
2015	$ 61,225
2016	61,906
2017	56,072
2018	53,083
2019	44,960
Thereafter	237,473
Total minimum lease payments	514,719
Less: Amount representing interest	(191,095)
Present value of minimum lease payments	$ 323,624

In thousands	Operating Leases
2015	$ 12,556
2016	12,532
2017	12,774
2018	12,730
2019	11,203
Thereafter	56,630
Total minimum lease payments	$ 118,425

In addition, we expect to receive approximately $12.4 million for 2015 through 2019 under our sublease agreements.

Commitments

We have entered into long-term commitments to purchase CO_2 that are either non-cancelable or cancelable only upon the occurrence of specified future events. The commitments continue for up to 17 years. The price we will pay for CO_2 generally varies depending on the amount of CO_2 delivered and the price of oil. Once all commitments have commenced (currently expected in 2016), our annual commitment under these contracts could range from $47 million to $67 million per year, assuming a $60 per Bbl NYMEX oil price.

We are party to long-term contracts that require us to deliver CO_2 to our industrial CO_2 customers at various contracted prices, plus we have a CO_2 delivery obligation to Genesis related to two CO_2 volumetric production payments (“VPPs”). Based upon the maximum amounts deliverable as stated in the industrial contracts and the VPPs, we estimate that we may be obligated to deliver up to 273 Bcf of CO_2 to these customers over the next 14 years. The maximum volume required in any given year is approximately 74 MMcf/d, which we judge to be minor given the size of our Jackson Dome proven CO_2 reserves at December 31, 2014, our current production capabilities and our projected levels of CO_2 usage for our own tertiary flooding program.

In conjunction with the August 2011 Riley Ridge acquisition, we assumed the 20-year helium supply contract under which the original participants in Riley Ridge agreed to supply helium to a third-party purchaser. After the commencement date, the contract provides for the delivery of a minimum contracted quantity of helium, subject to adjustment after startup of the Riley Ridge gas processing facility, which, if not supplied in accordance with the terms of the contract, may obligate us to compensate the third-party helium purchaser for the amount of the shortfall in an amount not to exceed $8.0 million per year, or $46.0 million over the term of the contract.

Delhi Field Release

In June 2013, a release of well fluids, consisting of a mixture of carbon dioxide, saltwater, natural gas and oil, was discovered (and reported) within an area of the Denbury-operated Delhi Field located in northern Louisiana. We completed our remediation efforts with respect to such release during the fourth quarter of 2013; however, we continue to monitor the impacted area to confirm the effectiveness of the remediation efforts. During the years ended December 31, 2014 and 2013, we recorded $16.8 million and $114.0 million, respectively, of lease operating expenses related to this release and its remediation in our Consolidated Statements of Operations, which brings our total cost estimate to date with respect to these expenses to $130.8 million, of which we have paid $112.6 million. The $16.8 million of additional charges in 2014 primarily consist of our actual or estimated expenses related to third-party property and commercial damage claims that have been settled or asserted in connection with the release, which are expected to be recoverable under our insurance policies.

We maintain insurance policies to cover certain costs, damages and claims related to releases of well fluids and remediation. We received a $25.0 million cost reimbursement ($23.9 million net to Denbury) in October 2014 related to the Delhi Field release and remediation from our insurance carrier providing the first layer of our excess insurance coverage, representing approximately 20% of our total incident costs through year-end 2014. The insurance reimbursement was recognized as a reduction to lease operating expenses in our Consolidated Statement of Operations for the year ended December 31, 2014. We have not reached any agreement with our remaining carriers as to further reimbursements, but given our belief that under our policies we are entitled to reimbursement of between approximately one-third and two-thirds of our total costs, we have filed suit to pursue further reimbursements, the ultimate outcome of which cannot be predicted.

Litigation

We are involved in various lawsuits, claims and regulatory proceedings incidental to our businesses. While we currently believe that the ultimate outcome of these proceedings, individually and in the aggregate, will not have a material adverse effect on our financial position, results of operations or cash flows, litigation is subject to inherent uncertainties. If an unfavorable ruling were to occur, there exists the possibility of a material adverse impact on our net income in the period in which the ruling occurs. We provide accruals of probable losses for litigation and claims if we determine that a loss is probable and the amount can be reasonably estimated.

Other Contingencies

We are subject to audits for various taxes (income, sales and use, and severance) in the various states in which we operate, and from time to time receive assessments for potential taxes that we may owe. In the past, settlement of these matters has not had a material adverse financial impact on us, and currently we have no material assessments for potential taxes.

We are subject to various possible contingencies that arise primarily from interpretation of federal and state laws and regulations affecting the oil and natural gas industry. Such contingencies include differing interpretations as to the prices at which oil and natural gas sales may be made, the prices at which royalty owners may be paid for production from their leases, environmental issues and other matters. Although we believe that we have complied with the various laws and regulations, administrative rulings and interpretations thereof, adjustments could be required as new interpretations and regulations are issued. In addition, production rates, marketing and environmental matters are subject to regulation by various federal and state agencies.

Note 12. Additional Balance Sheet Details

Trade and Other Receivables, Net

	December 31,	
In thousands	2014	2013
Commodity derivatives settlement receivables	$ 59,755	$ —
Trade accounts receivable, net	45,407	53,737
Federal income tax receivable, net	37,652	—
Other receivables	14,141	24,558
Total	$156,955	$78,295

Allowance for Doubtful Accounts

We record an allowance for doubtful accounts for receivables that we determine to be uncollectible based on the specific identification basis. The allowance for doubtful accounts, which is netted against “Trade and other receivables” on the Consolidated Balance Sheets, was $0.4 million and $0.3 million at December 31, 2014 and 2013, respectively.

Accounts Payable and Accrued Liabilities

In thousands	December 31, 2014	December 31, 2013
Accrued exploration and development costs	$ 90,939	$100,564
Accounts payable	64,604	63,263
Accrued compensation	62,513	55,043
Accrued lease operating expenses	56,798	59,762
Accrued interest	48,255	68,871
Taxes payable	39,816	28,019
Other	31,833	35,021
Total	$394,758	$410,543

Note 13. Supplemental Cash Flow Information

Supplemental Cash Flow Information

In thousands	Year Ended December 31, 2014	2013	2012
Supplemental cash flow information			
Cash paid for interest, expensed	$185,140	$ 117,442	$ 137,950
Cash paid for interest, capitalized	24,202	79,253	77,432
Cash paid for income taxes	5,033	28,895	99,194
Cash received from income tax refunds	(13,193)	(17,087)	(38,004)
Noncash investing activities			
Increase in asset retirement obligations	6,500	26,946	56,290
Increase (decrease) in liabilities for capital expenditures	215	(18,321)	(26,882)
Increase in restricted cash (1)	—	—	1,262,559
Decrease in restricted cash (2)	—	1,050,328	212,544

(1) During 2012, $212.5 million of proceeds from the sale of certain non-core assets in the Gulf Coast Region and $1.05 billion of the cash proceeds from the Bakken Exchange Transaction were paid by the respective purchaser directly to a qualified intermediary to facilitate a like-kind-exchange transaction for federal income tax purposes.

(2) During 2012 and 2013, proceeds from the sales of our oil and natural gas property dispositions in 2012, which were held by a qualified intermediary, were released in 2012 to fund the Thompson Field acquisition and in 2013 primarily to fund a portion of the CCA acquisition and certain post-closing costs under the Bakken Exchange Transaction.

Note 14. Subsequent Events

Equity Award Grant

The Compensation Committee of our Board of Directors granted long-term equity incentive awards to our employees under the 2004 Plan on January 9, 2015. The grants included 3,453,425 shares of restricted stock valued at $7.31 per share (the closing price of Denbury's common stock on January 9, 2015). The awards generally vest 33% per year over a three-year period.

Dividend Declaration

On January 27, 2015, the Board of Directors declared a dividend of $0.0625 per share on our outstanding common stock, payable on March 31, 2015, to stockholders of record at the close of business on February 24, 2015.

Supplemental Oil and Natural Gas Disclosures (Unaudited)

Costs Incurred

The following table summarizes costs incurred and capitalized in oil and natural gas property acquisition, exploration and development activities. Property acquisition costs are those costs incurred to purchase, lease or otherwise acquire property, including both undeveloped leasehold and the purchase of reserves in place. Exploration costs include costs of identifying areas that may warrant examination and examining specific areas that are considered to have prospects containing oil and natural gas reserves, including costs of drilling exploratory wells, geological and geophysical costs, and carrying costs on undeveloped properties. Development costs are incurred to obtain access to proved reserves, including the cost of drilling development wells, and to provide facilities for extracting, treating, gathering and storing the oil and natural gas, and the cost of improved recovery systems.

We capitalize interest on unevaluated oil and natural gas properties that have ongoing development activities. Included in costs incurred in the table below is capitalized interest of $21.8 million in 2014, $41.3 million in 2013 and $36.5 million in 2012. Costs incurred also include new asset retirement obligations established, as well as changes to asset retirement obligations resulting from revisions in cost estimates or abandonment dates. Asset retirement obligations included in the table below were $4.9 million in 2014, $17.1 million in 2013 and $38.8 million in 2012. See Note 3, *Asset Retirement Obligations,* for additional information.

Costs incurred in oil and natural gas activities were as follows:

	Year Ended December 31,		
In thousands	2014	2013	2012
Property acquisitions			
Proved	$ 3,801	$ 803,837	$ 491,041
Unevaluated	8,028	221,173	115,270
Exploration	5,493	2,103	12,019
Development	964,726	913,093	1,111,314
Total costs incurred (1)	$982,048	$1,940,206	$1,729,644

(1) Capitalized general and administrative costs that directly relate to exploration and development activities were $62.2 million, $55.4 million and $49.2 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Oil and Natural Gas Operating Results

Results of operations from oil and natural gas producing activities, excluding corporate overhead and interest costs, were as follows:

	Year Ended December 31,		
In thousands, except per BOE data	2014	2013	2012
Oil, natural gas, and related product sales	$2,372,473	$2,466,234	$2,409,867
Lease operating costs	647,559	730,574	532,359
Marketing expenses, net of third-party purchases, and plant operating expenses	47,965	37,754	41,936
Production and ad valorem taxes	155,495	162,791	149,919
Depletion, depreciation, and amortization	494,402	426,668	448,424
CO_2 properties and pipelines depletion and depreciation (1)	58,759	52,932	42,064
Commodity derivatives expense (income)	(555,255)	41,024	(4,834)
Net operating income	1,523,548	1,014,491	1,199,999
Income tax provision	578,948	385,507	462,000
Results of operations from oil and natural gas producing activities	$ 944,600	$ 628,984	$ 737,999
Depletion, depreciation, and amortization per BOE	$ 20.36	$ 18.71	$ 18.69

(1) Represents an allocation of the depletion, depreciation, and amortization of our CO_2 properties and pipelines associated with our tertiary oil producing activities.

Oil and Natural Gas Reserves

Net proved oil and natural gas reserve estimates for all years presented were prepared by DeGolyer and MacNaughton, independent petroleum engineers located in Dallas, Texas. These oil and natural gas reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties. See *Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves* below for a discussion of the effect of the different prices on reserve quantities and values. Operating costs, production and ad valorem taxes, and future development costs were based on current costs as of December 31, 2014.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. Moreover, the present values should not be construed as the current market value of our oil and natural gas reserves or the costs that would be incurred to obtain equivalent reserves. Estimates of reserves as of year-end 2014, 2013 and 2012 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the applicable fiscal 12-month period. All of our reserves are located in the United States.

Estimated Quantities of Proved Reserves

	Year Ended December 31,								
	2014			2013			2012		
	Oil (MBbl)	Gas (MMcf)	Total (MBOE)	Oil (MBbl)	Gas (MMcf)	Total (MBOE)	Oil (MBbl)	Gas (MMcf)	Total (MBOE)
Balance at beginning of year	386,659	489,954	468,318	329,124	481,641	409,398	357,733	625,208	461,934
Revisions of previous estimates	2,132	(36,796)	(4,000)	4,704	60	4,714	(7,099)	(16,720)	(9,886)
Revisions due to change in sales prices	(1,971)	7,789	(673)	665	14,100	3,015	(401)	(37,969)	(6,729)
Extensions and discoveries	—	—	—	118	—	118	14,910	10,005	16,579
Improved recovery [1]	1,468	—	1,468	34,015	—	34,015	69,543	—	69,543
Production	(25,771)	(8,379)	(27,168)	(24,194)	(8,666)	(25,639)	(24,462)	(10,654)	(26,238)
Acquisition of minerals in place	—	—	—	42,227	2,819	42,697	24,677	20,598	28,110
Sales of minerals in place	(182)	(166)	(210)	—	—	—	(105,777)	(108,827)	(123,915)
Balance at end of year	362,335	452,402	437,735	386,659	489,954	468,318	329,124	481,641	409,398
Proved Developed Reserves									
Balance at beginning of year	276,392	72,095	288,408	236,009	64,191	246,708	239,741	125,970	260,736
Balance at end of year	269,377	416,421	338,780	276,392	72,095	288,408	236,009	64,191	246,708

(1) Improved recovery reflects reserve additions that result from the application of secondary recovery methods such as water flooding, or tertiary recovery methods such as CO_2 flooding. In order to recognize proved tertiary oil reserves, we must either have an oil production response to CO_2 injections or the field must be analogous to an existing tertiary flood. The magnitude of proved reserves that we can book in any given year will depend on our progress with new floods and the timing of the production response.

There were no significant additions to our oil and natural gas reserves in 2014, as the magnitude of proved reserves that we can book in any given year depends on our progress with new floods and the timing of the production response, and we initiated no new floods in 2014. Revisions of previous estimates in 2014 primarily relate to natural gas reserves at Riley Ridge and Delhi fields previously classified as proved, which are now planned to be consumed as fuel.

Acquisitions of minerals in place during 2013 were primarily related to the acquisition of additional interests in certain of our existing operated fields in CCA, as well as operating interests in other CCA fields. Reserves added as a result of improved recovery represent initial proved tertiary oil reserves at Bell Creek Field.

We added 114.2 MMBOE of estimated proved reserves during 2012, including tertiary reserves of 69.5 MMBbls, primarily at Hastings and Oyster Bayou fields; 25.9 MMBOE from the acquisition of interests in the Thompson, Webster and Hartzog Draw fields; and 11.5 MMBOE from our Bakken area assets prior to their sale in the fourth quarter of 2012. These increases were offset by the disposition of 123.9 MMBOE of reserves associated with disposed properties, including our Bakken area assets, and non-core assets in the Gulf Coast region and Paradox Basin in Utah.

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

The Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves ("Standardized Measure") does not purport to present the fair market value of our oil and natural gas properties. An estimate of such value should consider, among other factors, anticipated future prices of oil and natural gas, the probability of recoveries in excess of existing proved reserves, the value of probable reserves and acreage prospects, and perhaps different discount rates. It should be noted that estimates of reserve quantities, especially from new discoveries, are inherently imprecise and subject to substantial revision.

Under the Standardized Measure, future cash inflows were estimated by applying a first-day-of-the-month 12-month average price to the estimated future production of year-end proved reserves. The product prices used to calculate these reserves have varied widely during the three-year period. These prices have a significant impact on both the quantities and value of the proved reserves, as reductions in oil and natural gas prices can cause wells to reach the end of their economic life much sooner and can make certain proved undeveloped locations uneconomical, both of which reduce the reserves. The following representative oil and natural gas prices were used in the Standardized Measure. These prices were adjusted by field to arrive at the appropriate corporate net price.

	December 31,		
	2014	2013	2012
Oil (NYMEX price per Bbl)	$94.99	$96.94	$94.71
Natural Gas (Henry Hub price per MMBtu)	4.30	3.67	2.85

The representative oil prices in the table above are not reflective of late 2014 and early 2015 significant crude oil price declines. In late 2014 and early 2015, oil prices dropped rapidly, declining to below $45 per Bbl in January 2015. In response to these price decreases, we have deferred our development spending for certain projects in 2015, which has been reflected in our December 31, 2014 reserve report. Sustained prices at these recent levels would result in a significant decrease in the future cash inflows associated with our proved reserve value, and to a lesser degree, a reduction in proved reserve volumes. The decrease in the Standardized Measure of discounted future net cash flows during 2014 in the tables that follow was significantly impacted by the decline in oil prices we received relative to NYMEX oil prices (our NYMEX oil price differential) between 2013 and 2014. The weighted-average oil price differentials utilized were $3.10 per Bbl below representative NYMEX oil prices as of December 31, 2014, compared to $3.41 per Bbl and $7.57 per Bbl above representative NYMEX oil prices as of December 31, 2013 and 2012, respectively.

Future cash inflows were reduced by estimated future production, development and abandonment costs based on current cost, with no escalation to determine pre-tax cash inflows. Our future net inflows do not include a reduction for cash previously expended on our capitalized CO_2 assets that will be consumed in the production of proved tertiary reserves. Future income taxes were computed by applying the statutory tax rate to the excess of net cash inflows over our tax basis in the associated proved oil and natural gas properties. Tax credits and net operating loss carryforwards were also considered in the future income tax calculation. Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the Standardized Measure.

	December 31,		
In thousands	2014	2013	2012
Future cash inflows	$ 34,761,067	$ 40,065,019	$ 34,779,549
Future production costs	(14,563,782)	(16,053,734)	(13,114,740)
Future development costs	(2,319,727)	(2,552,194)	(2,034,174)
Future income taxes	(5,711,897)	(6,937,773)	(6,672,857)
Future net cash flows	12,165,661	14,521,318	12,957,778
10% annual discount for estimated timing of cash flows	(6,257,533)	(7,392,574)	(6,543,398)
Standardized measure of discounted future net cash flows	$ 5,908,128	$ 7,128,744	$ 6,414,380

The following table sets forth an analysis of changes in the Standardized Measure of Discounted Future Net Cash Flows from proved oil and natural gas reserves:

	Year Ended December 31,		
In thousands	2014	2013	2012
Beginning of year	$ 7,128,744	$ 6,414,380	$ 7,007,605
Sales of oil and natural gas produced, net of production costs (1)	(1,521,529)	(1,649,113)	(1,673,253)
Net changes in prices and production costs	(1,415,154)	(170,571)	(597,512)
Extensions and discoveries, less applicable future development and production costs	—	4,902	291,558
Improved recovery (2)	51,793	739,019	1,901,109
Previously estimated development costs incurred	472,154	393,537	376,199
Change in future development costs	(289,622)	(301,162)	(454,140)
Revisions due to timing and other	(205,912)	(446,586)	(330,849)
Accretion of discount	1,020,008	1,072,113	875,383
Acquisition of minerals in place	—	1,082,050	767,267
Sales of minerals in place	2,549	—	(1,805,309)
Net change in income taxes	665,097	(9,825)	56,322
End of year	$ 5,908,128	$ 7,128,744	$ 6,414,380

(1) Production costs exclude a net reduction of $7.1 million in lease operating expenses recorded during the year ended December 31, 2014, related to the Delhi Field release, and a charge of $114.0 million of lease operating expenses recorded during the year ended December 31, 2013, related to that release.

(2) Improved recovery additions result from the application of secondary recovery methods such as water flooding or tertiary recovery methods such as CO_2 flooding.

Supplemental CO_2 and Helium Disclosures (Unaudited)

Based on engineering reports prepared by DeGolyer and MacNaughton, proved CO_2 reserves, and helium reserves associated with our helium production rights, were estimated as follows (in MMcf):

	Year Ended December 31,		
	2014	2013	2012
CO_2 reserves			
Gulf Coast region (1)	5,697,642	6,070,619	6,073,175
Rocky Mountain region (2)	3,035,286	3,272,428	3,495,534
Helium reserves associated with Denbury's production rights			
Rocky Mountain region (3)	13,231	13,251	12,712

(1) Proved CO_2 reserves in the Gulf Coast region consist of reserves from our reservoirs at Jackson Dome and are presented on a gross working interest (8/8ths) basis, of which our net revenue interest was approximately 4.5 Tcf, 4.8 Tcf and 4.8 Tcf at December 31, 2014, 2013 and 2012, respectively, and include reserves dedicated to volumetric production payments of 9.3 Bcf, 28.9 Bcf and 57.1 Bcf at December 31, 2014, 2013 and 2012, respectively.

(2) Proved CO_2 reserves in the Rocky Mountain region consist of our reserves at Riley Ridge (presented on a gross working interest (8/8ths) basis) and our overriding royalty interest in LaBarge Field, of which our net revenue interest was approximately 2.6 Tcf, 2.9 Tcf and 2.9 Tcf at December 31, 2014, 2013 and 2012, respectively.

(3) Reserves associated with helium production rights include helium reserves located in acreage in the Rocky Mountain region for which we have the contractual right to extract the helium on behalf of the U.S. government, which owns the helium. Our extraction agreement with the U.S. government gives us the ability to produce the helium on behalf of the U.S. government in exchange for a fee, which amount fluctuates based upon the realized sales proceeds we receive for the helium. The estimate of helium reserves is reduced to reflect the estimated fee we will remit to the U.S. government. Our extraction agreement with the U.S. government has a minimum term extending 20 years from first production and continuing thereafter until either party terminates the contract. Reserve volumes presented herein assume that the term of this helium extraction agreement continues beyond 20 years, given the benefit to both parties to the agreement.

Unaudited Quarterly Information

In thousands, except per-share data	March 31	June 30	September 30	December 31
2014				
Revenues and other income	$ 641,744	$ 672,120	$ 637,657	$ 483,684
Commodity derivatives expense (income)	76,669	174,771	(252,265)	(554,430)
Loss on early extinguishment of debt	—	113,908	—	—
Other expenses (1)	471,972	471,505	453,604	456,914
Net income (loss)	58,310	(55,200)	268,748	363,633
Net income (loss) per common share:				
Basic	0.17	(0.16)	0.77	1.04
Diluted	0.17	(0.16)	0.77	1.04
Dividends declared per common share	0.0625	0.0625	0.0625	0.0625
Cash flow provided by operating activities	214,858	329,847	340,392	337,728
Cash flow used in investing activities	(236,754)	(280,148)	(272,021)	(287,832)
Cash flow provided by (used in) financing activities	17,601	(45,545)	(60,981)	(46,179)
2013				
Revenues and other income	$ 583,086	$ 650,084	$ 684,835	$ 599,122
Commodity derivatives expense (income)	11,929	(45,501)	80,446	(5,850)
Loss on early extinguishment of debt	44,223	428	—	—
Other expenses (1)	384,999	483,851	445,024	475,198
Net income	87,571	129,980	102,054	89,992
Net income per common share:				
Basic	0.24	0.35	0.28	0.25
Diluted	0.23	0.35	0.28	0.25
Cash flow provided by operating activities	269,176	437,568	305,465	348,986
Cash flow used in investing activities	(320,646)	(344,927)	(286,130)	(323,606)
Cash flow provided by (used in) financing activities	15,228	(79,045)	(68,652)	(39,741)

(1) Includes $2.8 million, ($9.9 million), $16.0 million, $28.0 million, and $70.0 million related to Delhi remediation charges, net of insurance reimbursements during the three months ended in December 31, 2014, September 30, 2014, December 31, 2013, September 30, 2013, and June 30, 2013, respectively.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) was performed under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2014, to ensure that information that is required to be disclosed in the reports the Company files and submits under the Securities Exchange Act of 1934 is recorded; that it is processed, summarized and reported within the time periods specified in the SEC's rules and forms; and that information that is required to be disclosed under the Exchange Act is accumulated and communicated to management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Evaluation of Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we have determined that, during the fourth quarter of fiscal 2014, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of the end of the period covered by this report based on the framework in "Internal Control – Integrated Framework" (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, our Chief Executive Officer and our Chief Financial Officer concluded that our internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of our financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

The effectiveness of our internal control over financial reporting as of December 31, 2014, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in the report that appears herein.

Important Considerations

The effectiveness of our disclosure controls and procedures and our internal control over financial reporting is subject to various inherent limitations, including cost limitations, judgments used in decision making, assumptions about the likelihood of future events, the soundness of our systems, the possibility of human error, and the risk of fraud. Moreover, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions and the risk that the degree of compliance with policies or procedures may deteriorate over time. Because of these limitations, there can be no assurance that any system of disclosure controls and procedures or internal control over financial reporting will be successful in preventing all errors or fraud or in making all material information known in a timely manner to the appropriate levels of management.

Item 9B. Other Information

None.

Item 10. Directors, Executive Officers and Corporate Governance

Except as disclosed below, information as to Item 10 will be set forth in the Proxy Statement ("Proxy Statement") for the Annual Meeting of Shareholders to be held May 19, 2015 ("Annual Meeting") and is incorporated herein by reference.

Code of Ethics

We have adopted a Code of Ethics for Senior Financial Officers and the Principal Executive Officer. This Code of Ethics, including any amendments or waivers, is posted on our website at www.denbury.com.

Item 11. Executive Compensation

Information as to Item 11 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information as to Item 12 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information as to Item 13 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

Information as to Item 14 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 15. Exhibits and Financial Statement Schedules

Financial Statements and Schedules. Financial statements and schedules filed as a part of this report are presented on page 60. All financial statement schedules have been omitted because they are not applicable, or the required information is presented in the financial statements or the notes to consolidated financial statements.

Exhibits. The following exhibits are included as part of this report.

Exhibit No.	Exhibit
2(a)	Exchange Agreement, dated as of September 19, 2012, by and among Denbury Onshore, LLC, XTO Energy Inc., and Exxon Mobil Corporation (incorporated by reference to Exhibit 2.1 of Form 8-K filed by the Company on September 25, 2012, File No. 001-12935).
2(b)	Closing Agreement and Amendment, dated as of November 30, 2012, by and among Denbury Onshore, LLC, XTO Energy Inc., and Exxon Mobil Corporation (incorporated by reference to Exhibit 2.2 of Form 8-K filed by the Company on December 6, 2012, File No. 001-12935).
2(c)	Second Closing Agreement and Amendment, dated as of December 21, 2012, by and among Denbury Onshore, LLC, XTO Energy Inc., and Exxon Mobil Corporation (incorporated by reference to Exhibit 2.1 of Form 8-K filed by the Company on December 26, 2012, File No. 001-12935).
2(d)	Purchase and Sale Agreement, dated as of January 14, 2013, by and between Burlington Resources Oil & Gas Company LP and Denbury Onshore, LLC (incorporated by reference to Exhibit 2.1 of Form 8-K filed by the Company on January 15, 2013, File No. 001-12935).
3(a)	Second Restated Certificate of Incorporation of Denbury Resources Inc. filed with the Delaware Secretary of State on October 30, 2014 (incorporated by reference to Exhibit 3(a) of Form 10-Q filed by the Company on November 7, 2014, File No. 001-12935).
3(b)	Second Amended and Restated Bylaws of Denbury Resources Inc. as of November 4, 2014 (incorporated by reference to Exhibit 3(b) of Form 10-Q filed by the Company on November 7, 2014, File No. 001-12935).
4(a)	Indenture for 8¼% Senior Subordinated Notes due 2020, dated as of February 10, 2010, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on February 12, 2010, File No. 001-12935).
4(b)	First Supplemental Indenture for 8¼% Senior Subordinated Notes due 2020, dated as of March 9, 2010, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.7 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(c)	Second Supplemental Indenture for 8¼% Senior Subordinated Notes due 2020, dated as of February 3, 2011, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4(s) of Form 10-K filed by the Company on March 1, 2011, File No. 001-12935).
4(d)	Third Supplemental Indenture for 8¼% Senior Subordinated Notes due 2020, dated as of April 30, 2014, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 of Form 8-K filed by the Company on May 1, 2014, File No. 001-12935).
4(e)	Indenture for 6.25% Senior Subordinated Notes Due 2014, dated as of April 2, 2004, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1.1 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(f)	First Supplemental Indenture for 6.25% Senior Subordinated Notes Due 2014, dated as of January 2, 2008, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1.2 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(g)	Second Supplemental Indenture for 6.25% Senior Subordinated Notes Due 2014, dated as of January 27, 2010, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1.3 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).

Exhibit No.	Exhibit
4(h)	Third Supplemental Indenture for 6.25% Senior Subordinated Notes Due 2014, dated as of March 10, 2010, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1.4 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(i)	Fourth Supplemental Indenture for 6.25% Senior Subordinated Notes Due 2014, dated as of February 3, 2011, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4(x) of Form 10-K filed by the Company on March 1, 2011, File No. 001-12935).
4(j)	Indenture for 6.0% Senior Subordinated Notes due 2015, dated as of July 13, 2005, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2.1 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(k)	First Supplemental Indenture for 6.0% Senior Subordinated Notes due 2015, dated as of January 2, 2008, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2.2 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(l)	Second Supplemental Indenture for 6.0% Senior Subordinated Notes due 2015, dated as of January 27, 2010, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2.3 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(m)	Third Supplemental Indenture for 6.0% Senior Subordinated Notes due 2015, dated as of March 10, 2010, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2.4 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(n)	Fourth Supplemental Indenture for 6.0% Senior Subordinated Notes due 2015, dated as of February 3, 2011, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4(cc) of Form 10-K filed by the Company on March 1, 2011, File No. 001-12935).
4(o)	Indenture for Subordinated Debt Securities, dated as of November 16, 2005, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3.1 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(p)	First Supplemental Indenture for 7.25% Senior Subordinated Notes due 2017, dated as of November 23, 2005, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3.2 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(q)	Second Supplemental Indenture for 7.25% Senior Subordinated Notes due 2017, dated as of January 2, 2008, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3.3 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(r)	Third Supplemental Indenture for 9.5% Senior Subordinated Notes due 2016, dated as of April 27, 2009, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3.4 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(s)	Fourth Supplemental Indenture for Senior Subordinated Notes, dated as of January 27, 2010, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3.5 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(t)	Fifth Supplemental Indenture for Senior Subordinated Notes, dated as of March 10, 2010, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3.6 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(u)	Sixth Supplemental Indenture for Senior Subordinated Notes, dated as of February 3, 2011, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4(jj) of Form 10-K filed by the Company on March 1, 2011, File No. 001-12935).
4(v)	Seventh Supplemental Indenture for Senior Subordinated Notes, dated as of February 5, 2013, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 of Form 8-K filed by the Company on February 5, 2013, File No. 001-12935).

Exhibit No.	Exhibit
4(w)	Indenture for 6⅜% Senior Subordinated Notes due 2021, dated as of February 17, 2011, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on February 22, 2011, File No. 001-12935).
4(x)*	First Supplemental Indenture for 6⅜% Senior Subordinated Notes due 2021, dated as of December 31, 2014, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee.
4(y)	Indenture for 4⅝% Senior Subordinated Notes due 2023, dated as of February 5, 2013, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on February 5, 2013, File No. 001-12935).
4(z)*	First Supplemental Indenture for 4⅝% Senior Subordinated Notes due 2023, dated as of December 31, 2014, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee.
4(aa)	Indenture for 5½% Senior Subordinated Notes due 2022, dated as of April 30, 2014, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on May 1, 2014, File No. 001-12935).
4(bb)*	First Supplemental Indenture for 5½% Senior Subordinated Notes due 2022, dated as of December 31, 2014, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee.
10(a)	Credit Agreement, dated as of March 9, 2010, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
10(b)	First Amendment to Credit Agreement, dated as of May 13, 2010, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on May 19, 2010, File No. 001-12935).
10(c)	Second Amendment to Credit Agreement, dated as of September 30, 2010, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10.1 of Form 10-Q filed by the Company on November 9, 2010, File No. 001-12935).
10(d)	Third Amendment to Credit Agreement, dated as of December 17, 2010, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10(d) of Form 10-K filed by the Company on March 1, 2011, File No. 001-12935).
10(e)	Fourth Amendment to Credit Agreement, dated as of February 1, 2011, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10(e) of Form 10-K filed by the Company on March 1, 2011, File No. 001-12935).
10(f)	Fifth Amendment to Credit Agreement, dated as of May 19, 2011, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 99.1 of Form 8-K filed by the Company on May 20, 2011, File No. 001-12935).
10(g)	Sixth Amendment to Credit Agreement, dated as of September 1, 2011, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on September 8, 2011, File No. 001-12935).
10(h)	Seventh Amendment to Credit Agreement, dated as of April 11, 2012, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 4(a) of Form 10-Q filed by the Company on May 10, 2012, File No. 001-12935).
10(i)	Eighth Amendment to Credit Agreement, dated as of July 26, 2012, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 4(a) of Form 10-Q filed by the Company on August 8, 2012, File No. 001-12935).
10(j)	Ninth Amendment to Credit Agreement, dated as of November 2, 2012, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10(a) of Form 10-Q filed by the Company on November 8, 2012, File No. 001-12935).

Exhibit No.	Exhibit
10(k)	Tenth Amendment to Credit Agreement, dated as of January 18, 2013, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10(k) of Form 10-K filed by the Company on February 28, 2013, File No. 001-12935).
10(l)	Eleventh Amendment to Credit Agreement and First Amendment to Facility Guarantees, dated as of November 8, 2013, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10(l) of Form 10-K filed by the Company on February 28, 2014, File No. 001-12935).
10(m)	Twelfth Amendment to Credit Agreement, dated as of April 15, 2014, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on April 17, 2014, File No. 001-12935).
10(n)	Amended and Restated Credit Agreement, dated as of December 9, 2014, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lending institutions party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on December 15, 2014, File No. 001-12935).
10(o)	Pipeline Financing Lease Agreement, dated as of May 30, 2008, by and between Genesis NEJD Pipeline, LLC, as Lessor, and Denbury Onshore, LLC, as Lessee (incorporated by reference to Exhibit 99.1 of Form 8-K filed by the Company on June 5, 2008, File No. 001-12935).
10(p)	Transportation Services Agreement, dated as of May 30, 2008, by and between Genesis Free State Pipeline, LLC and Denbury Onshore, LLC (incorporated by reference to Exhibit 99.2 of Form 8-K filed by the Company on June 5, 2008, File No. 001-12935).
10(q)**	Denbury Resources Inc. Amended and Restated Stock Option Plan, effective as of December 5, 2007 (incorporated by reference to Exhibit 99.2 of Form 8-K filed by the Company on December 11, 2007, File No. 001-12935).
10(r)**	Denbury Resources Inc. Amended and Restated Employee Stock Purchase Plan, effective as of May 22, 2013 (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on May 28, 2013, File No. 001-12935).
10(s)**	Form of Indemnification Agreement, dated as of July 28, 1999, by and between Denbury Resources Inc. and its officers and directors (incorporated by reference to Exhibit 10 of Form 10-Q filed by the Company on August 11, 1999, File No. 001-12935).
10(t)**	Denbury Resources Inc. Director Deferred Compensation Plan, as amended and restated effective as of December 12, 2013 (incorporated by reference to Exhibit 10(r) of Form 10-K filed by the Company on February 28, 2014, File No. 001-12935).
10(u)**	Denbury Resources Inc. Severance Protection Plan, as amended and restated effective as of December 13, 2012 (incorporated by reference to Exhibit 10(v) of Form 10-K filed by the Company on February 28, 2013, File No. 001-12935).
10(v)**	Denbury Resources Inc. 2004 Omnibus Stock and Incentive Plan, as amended and restated as of December 12, 2013 (incorporated by reference to Exhibit 10(t) of Form 10-K filed by the Company on February 28, 2014, File No. 001-12935).
10(w)**	2004 Form of Restricted Stock Award that vests on retirement for grants to officers pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(l) of Form 10-K filed by the Company on March 15, 2005, File No. 001-12935).
10(x)**	2012 Form of Performance Stock Award pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(a) of Form 10-Q filed by the Company on May 10, 2012, File No. 001-12935).
10(y)**	2012 Form of Performance Cash Award pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(b) of Form 10-Q filed by the Company on May 10, 2012, File No. 001-12935).
10(z)**	2012 Form of TSR Performance Award pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(c) of Form 10-Q filed by the Company on May 10, 2012, File No. 001-12935).
10(aa)**	2013 Form of Performance Share Award pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(a) of Form 10-Q filed by the Company on May 10, 2013, File No. 001-12935).
10(bb)**	2013 Form of Performance Cash Award pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(b) of Form 10-Q filed by the Company on May 10, 2013, File No. 001-12935).
10(cc)**	2013 Form of TSR Performance Award pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(c) of Form 10-Q filed by the Company on May 10, 2013, File No. 001-12935).

Exhibit No.	Exhibit
10(dd)**	2013 Form of Stock Appreciation Rights Agreement pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(e) of Form 10-Q filed by the Company on May 10, 2013, File No. 001-12935).
10(ee)**	2013 Form of Restricted Share Award to officers pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(d) of Form 10-Q filed by the Company on May 10, 2013, File No. 001-12935).
10(ff)**	2013 Form of Restricted Share Award to non-employee directors pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(c) of Form 10-Q filed by the Company on August 6, 2013, File No. 001-12935).
10(gg)**	2013 Form of Deferred Stock Unit Award pursuant to the Director Deferred Compensation Plan (with respect to deferred long-term incentive awards) (incorporated by reference to Exhibit 10(d) of Form 10-Q filed by the Company on August 6, 2013, File No. 001-12935).
10(hh)**	2013 Form of Deferred Stock Unit Agreement pursuant to the Director Deferred Compensation Plan (with respect to deferred director fees) (incorporated by reference to Exhibit 10(e) of Form 10-Q filed by the Company on August 6, 2013, File No. 001-12935).
10(ii)**	Officer Resignation Agreement, effective as of December 31, 2013, by and between Denbury Resources Inc. and Robert L. Cornelius (incorporated by reference to Exhibit 10(z) of Form 10-K filed by the Company on February 28, 2014, File No. 001-12935).
10(jj)**	2014 Form of Performance Cash Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(a) of Form 10-Q filed by the Company on May 12, 2014, File No. 001-12935).
10(kk)**	2014 Form of TSR Performance Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(b) of Form 10-Q filed by the Company on May 12, 2014, File No. 001-12935).
10(ll)**	2014 Form of Performance Capital Efficiency Share Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(c) of Form 10-Q filed by the Company on May 12, 2014, File No. 001-12935).
10(mm)**	2014 Form of Growth and Income Performance Share Award under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(d) of Form 10-Q filed by the Company on May 12, 2014, File No. 001-12935).
10(nn)**	2014 Form of Restricted Share Award Cliff Vesting Awards under the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(e) of Form 10-Q filed by the Company on May 12, 2014, File No. 001-12935).
10(oo)* **	Officer Resignation Agreement, effective as of November 14, 2014, by and between Denbury Resources Inc. and K. Craig McPherson.
10(pp)* **	Officer Resignation Agreement, effective as of November 14, 2014, by and between Denbury Resources Inc. and Charles E. Gibson.
21*	List of subsidiaries of Denbury Resources Inc.
23(a)*	Consent of PricewaterhouseCoopers LLP.
23(b)*	Consent of DeGolyer and MacNaughton.
31(a)*	Certification of Chief Executive Officer Pursuant to Section 302 of Sarbanes-Oxley Act of 2002.
31(b)*	Certification of Chief Financial Officer Pursuant to Section 302 of Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99*	The summary of DeGolyer and MacNaughton's Report as of December 31, 2014, on oil and gas reserves (SEC Case) dated January 27, 2015.

* Included herewith.

** Compensation arrangements.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Denbury Resources Inc. has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

DENBURY RESOURCES INC.

/s/ Mark C. Allen February 27, 2015

Mark C. Allen
Sr. Vice President and Chief Financial Officer

/s/ Alan Rhoades February 27, 2015

Alan Rhoades
Vice President and Chief Accounting Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of Denbury Resources Inc. and in the capacities and on the dates indicated.

/s/ Phil Rykhoek February 27, 2015

Phil Rykhoek
Director, President and Chief Executive Officer
(Principal Executive Officer)

/s/ John P. Dielwart February 27, 2015

John P. Dielwart
Director

/s/ Mark C. Allen February 27, 2015

Mark C. Allen
Sr. Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ Ronald G. Greene February 27, 2015

Ronald G. Greene
Director

/s/ Alan Rhoades February 27, 2015

Alan Rhoades
Vice President and Chief Accounting Officer
(Principal Accounting Officer)

/s/ Gregory L. McMichael February 27, 2015

Gregory L. McMichael
Director

/s/ Wieland F. Wettstein February 27, 2015

Wieland F. Wettstein
Director

/s/ Kevin O. Meyers February 27, 2015

Kevin O. Meyers
Director

/s/ Michael L. Beatty February 27, 2015

Michael L. Beatty
Director

/s/ Randy Stein February 27, 2015

Randy Stein
Director

/s/ Michael B. Decker February 27, 2015

Michael B. Decker
Director

/s/ Laura A. Sugg February 27, 2015

Laura A. Sugg
Director

Exhibit 21

LIST OF SUBSIDIARIES

Name Of Subsidiary	Jurisdiction Of Organization
Denbury Operating Company	Delaware
Denbury Onshore, LLC	Delaware
Denbury Pipeline Holdings, LLC	Delaware
Denbury Holdings, Inc.	Delaware
Denbury Green Pipeline – Texas, LLC	Delaware
Greencore Pipeline Company, LLC	Delaware
Denbury Gulf Coast Pipelines, LLC	Delaware

Exhibit 23(a)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (Nos. 333-01006, 333-27995, 333-55999, 333-70485, 333-39172, 333-39218, 333-39224, 333-63198, 333-90398, 333-106253, 333-116249, 333-143848, 333-160178, 333-167480, 333-175273 and 333-189438) and Form S-3 (No. 333-195305) of Denbury Resources Inc. of our report dated February 27, 2015 relating to the consolidated financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Dallas, Texas
February 27, 2015

Exhibit 23(b)

DEGOLYER AND MACNAUGHTON
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 26, 2015

DENBURY RESOURCES INC.
5320 Legacy Drive
Plano, Texas 75024

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to references to DeGolyer and MacNaughton, to the inclusion of our Letter Report dated January 27, 2015, regarding the proved reserves of Denbury Resources, and to the inclusion of information taken from our "Appraisal Report as of December 31, 2014 on Certain Properties owned by Denbury Resources Inc. SEC Case", "Appraisal Report as of December 31, 2013 on Certain Properties owned by Denbury Resources Inc. SEC Case", and "Appraisal Report as of December 31, 2012 on Certain Properties owned by Denbury Resources Inc. SEC Case", in the Annual Report on Form 10-K of Denbury Resources Inc. for the year ended December 31, 2014.

Very truly yours,

/s/ DeGolyer and MacNaughton

DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716

Exhibit 31(a)

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Phil Rykhoek, certify that:

1. I have reviewed this report on Form 10-K of Denbury Resources Inc. (the registrant);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Phil Rykhoek February 27, 2015

Phil Rykhoek
President and Chief Executive Officer

Exhibit 31(b)

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark C. Allen, certify that:

1. I have reviewed this report on Form 10-K of Denbury Resources Inc. (the registrant);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Mark C. Allen February 27, 2015

Mark C. Allen
Senior Vice President, Chief Financial Officer, Treasurer,
and Assistant Secretary

Exhibit 32

CERTIFICATION OF CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report on Form 10-K for the year ended December 31, 2014 (the Report) of Denbury Resources Inc. (Denbury) as filed with the Securities and Exchange Commission, each of the undersigned, in his capacity as an officer of Denbury, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Denbury.

/s/ Phil Rykhoek February 27, 2015

Phil Rykhoek
President and Chief Executive Officer

/s/ Mark C. Allen February 27, 2015

Mark C. Allen
Senior Vice President, Chief Financial Officer, Treasurer,
and Assistant Secretary

CORPORATE INFORMATION

STOCK EXCHANGE LISTING

New York Stock Exchange ("NYSE")
Ticker Symbol: DNR

CORPORATE HEADQUARTERS

Denbury Resources Inc.
5320 Legacy Drive
Plano, Texas 75024
972.673.2000
www.denbury.com

STOCK TRANSFER AGENT & REGISTRAR

For questions concerning dividends, stock certificates, transfer procedures or address changes, please contact:

American Stock Transfer and Trust Company
6201 15th Avenue
Brooklyn, NY 11219
800.937.5449
Email: info@amstock.com
www.amstock.com

INVESTOR INQUIRIES

Phil Rykhoek
President & Chief Executive Officer
972.673.2000

Mark Allen
Senior Vice President &
Chief Financial Officer
972.673.2000

Ross Campbell
Manager, Investor Relations
972.673.2825
Email: ross.campbell@denbury.com

ANNUAL CERTIFICATIONS

During 2014, our Chief Financial Officer certified to the NYSE that he is not aware of any violation by the Company of the NYSE's corporate governance listing standards.

FINANCIAL INFORMATION REQUESTS

For additional information and to receive additional copies of the Annual Report on Form 10-K as filed with the Securities and Exchange Commission ("SEC") or to obtain other Denbury public documents, please contact:

Denbury Resources Inc.
Investor Relations
5320 Legacy Drive
Plano, Texas 75024
972.673.2000
Email: ir@denbury.com

Our Form 10-K filed with the SEC is included herein, excluding all exhibits other than our Section 302, 404 and 906 certifications by the CEO and CFO. We will send shareholders our Form 10-K exhibits and any of our corporate governance documents, without charge, upon request. These documents are also available on our website at www.denbury.com.

ANNUAL MEETING

The Annual Meeting of the Stockholders will be held on Tuesday, May 19, 2015, at 3:00 P.M. CDT at Denbury's Corporate Headquarters at 5320 Legacy Drive, Plano, TX 75024.

LEGAL COUNSEL

Baker & Hostetler LLP

BANKERS

JP Morgan (Agent)

AUDITORS

PricewaterhouseCoopers LLP

RESERVE ENGINEERS

DeGolyer and MacNaughton

DNR LISTED NYSE

Designed by Eisenberg And Associates

MIX
Paper from responsible sources
FSC® C101537
www.fsc.org

Denbury Resources Inc.

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