DENBURY RESOURCES INC
Form 10-K
February 28, 2012

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

2011 FORM 10-K

(Mark One)
þ Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2011

OR

¨ 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 RESOURCES INC.
(Exact name of Registrant as specified in its charter)

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

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ 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 þ 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 definition of "large accelerated filer", "accelerated filer", and "small reporting company" in Rule 12-b2 of the Exchange Act.
Large accelerated filer þ Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

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

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 $6,990,650,460.

The number of shares outstanding of the registrant's Common Stock as of January 31, 2012, was 390,282,768.

DOCUMENTS INCORPORATED BY REFERENCE

Document:	Incorporated as to:
1.Notice and Proxy Statement for the Annual Meeting of Stockholders to be held May 15, 2012.	1. Part III, Items 10, 11, 12, 13, 14

Denbury Resources Inc.
2011 Annual Report on Form 10-K

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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 produced per day.
Bcf	One billion cubic feet of natural gas, CO2 or helium.
Bcfe	One billion cubic feet of natural gas equivalent, using the ratio of one barrel of crude oil, condensate or natural gas liquids to 6 Mcf of natural gas.
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.
CO2	Carbon dioxide.
EOR	Enhanced oil recovery.
Finding and Development Cost	The average cost per BOE to find and develop proved reserves during a given period. It is calculated by dividing costs, which includes the total acquisition, exploration and development costs incurred during the period plus future development and abandonment costs related to the specified property or group of properties, by the sum of (i) the change in total proved reserves during the period plus (ii) total production during that period.
MBbls	One thousand barrels of crude oil or other liquid hydrocarbons.
MBOE	One thousand BOEs.
Mbtu	One thousand Btus.
Mcf	One thousand cubic feet of natural gas, CO2 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, CO2 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.
PV-10 Value	When used with respect to oil and natural gas reserves, PV-10 Value means 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 its use is further discussed in footnote 3 to the reserves table included in Item 1, Estimated Net Quantities of Proved Oil and Natural Gas Reserves and Present Value of Estimated Future Net Revenues.
Probable Reserves*	Are those additional 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.

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Proved Developed Reserves*	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved Reserves*	The estimated quantities of 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 where a relatively major expenditure is required.
Tcf	One trillion cubic feet of natural gas, CO_2 or helium.

* This definition is an abbreviated version of the complete definition as defined by the SEC in Rule 4-10(a) of Regulation S-X. For the complete definition see http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&rgn=div5&view=text&node=17:2.0.1.1.8&idno=17#17:2.0.1.1.8.0.21.42.

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PART I

Item 1. Business and Properties

GENERAL

Denbury Resources Inc., a Delaware corporation, is a domestic independent oil and natural gas company with 461.9 million BOE of proved oil and natural gas reserves as of December 31, 2011, of which 77% is oil. We are the largest combined oil and natural gas producer in Mississippi and Montana, own the largest reserves of CO2 used for tertiary oil recovery east of the Mississippi River, and hold significant operating acreage in the Rocky Mountain and Gulf Coast regions. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling and proven engineering extraction practices, with our most significant emphasis relating to tertiary recovery operations.

As part of our corporate strategy, we believe in the following fundamental principles:

- focus in specific regions where we either have, or believe we can create, a competitive advantage as a result of our ownership or use of CO2 reserves, oil fields and CO2 infrastructure;
- acquire 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 of our properties by increasing production and reserves while controlling cost; and
- maintain a highly competitive team of experienced and incentivized personnel.

Denbury became a Canadian public company in 1992 through a reverse merger with a Canadian company that was originally incorporated in Canada in 1951. In 1999, we moved our corporate domicile from Canada to the United States as a Delaware corporation and have been publicly traded in the United States since 1995 and on the New York Stock Exchange since May 1997.

Our corporate headquarters is located at 5320 Legacy Drive, Plano, Texas 75024, and our phone number is 972-673-2000. At December 31, 2011, we had 1,308 employees, 730 of whom were employed in field operations or at the 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 Internet website, www.denbury.com, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The SEC also maintains a website, www.sec.gov, which contains reports, proxy and information statements and other information filed by Denbury. Throughout this Form 10-K we use the terms “Denbury,” “Company,” “we,” “our,” and “us” to refer to Denbu Resources Inc. and, as the context may require, its subsidiaries.

2010 ENCORE ACQUISITION AND RELATED DISPOSITIONS

On March 9, 2010, we acquired Encore Acquisition Company (“Encore”) pursuant to an Agreement and Plan of Merger (the "Encore Merger Agreement") in a stock and cash transaction valued at approximately $4.8 billion at the acquisition date, including the assumption of Encore debt and the value of the noncontrolling interest in Encore Energy Partners LP ("ENP"). Under the Encore Merger Agreement, Encore was merged with and into Denbury (the "Encore Merger"), with Denbury surviving the Encore Merger. Pursuant to our stated intent, at the time of acquisition, to divest certain non-strategic legacy Encore properties, certain oil and gas properties in the Permian Basin, Mid-continent area and East Texas Basin were sold in May 2010. We subsequently divested our production and acreage in the Cleveland Sand Play and Haynesville Play during 2010 as well. In addition to the property sales, we sold our ownership interests in ENP on December 31, 2010. Collectively, we received approximately $1.5 billion in total consideration from these divestitures in 2010, excluding the bank debt of ENP that was assumed by the purchaser in the sale. See Note 2, Acquisitions and Divestitures, to the Consolidated Financial Statements for further discussion of these transactions and information as to other recent acquisitions and divestitures by Denbury.

OIL AND NATURAL GAS OPERATIONS

Summary. Our oil and natural gas properties are concentrated in the Gulf Coast and Rocky Mountain regions in 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 primarily situated in Montana, North Dakota, Utah and Wyoming. Our primary focus is using CO2 in enhanced oil recovery ("EOR"), which we have been doing actively for over 12 years in the Gulf Coast region. EOR, which we also refer to as "tertiary recovery" (as opposed to primary and secondary recovery), is a term used to represent techniques for extracting incremental oil out of existing oil fields. We acquired Encore during 2010 with the intent to employ our tertiary recovery strategy using CO2 throughout the Rocky Mountain region. As part of the Encore Merger, we obtained a significant acreage position in the Bakken play in North Dakota, one of the more significant oil plays in North America. Our current properties provide us significant growth potential through the remainder of this decade.

Our Gulf Coast EOR operations are driven by CO_2 produced from our natural source at Jackson Dome, Mississippi, which is transported to our Gulf Coast tertiary fields through pipelines that we either own or control through long-term financing leases. In the Rocky Mountain region, we made significant strides in executing our EOR strategy during 2011. We were able to secure significant Rocky Mountain CO_2 reserves with the acquisition of the remaining interest in the Riley Ridge Federal Unit ("Riley Ridge"), and we completed the first 115 miles of the initial 232-mile segment of the 20-inch Greencore CO_2 pipeline, which will serve as part of our trunk-line in the region. Although our development of tertiary fields, CO_2 sources and pipelines in this new area is just beginning, we believe that Riley Ridge and other potential sources of CO_2 in the area will allow us to utilize CO_2 injection to potentially recover significant amounts of incremental oil from old oil fields. Each of our significant development areas and planned activities is discussed in more detail below.

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, 2011, and average daily production and net revenue interest ("NRI") for 2011. The reserve estimates for all years presented were prepared by DeGolyer and MacNaughton, 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 net revenue interest due to royalties and other burdens. For additional reserve information, see Estimated Net Quantities of Proved Oil and Natural Gas Reserves and Present Value of Estimated Future Net Revenues below.

Denbury Resources Inc.

	Proved Reserves as of December 31, 2011(1)					2011 Average Daily Production		
	Oil (MBbls)	Natural Gas (MMcf)	MBOEs	BOE % of total	PV-10 Value(2) (000's)	Oil (Bbls/d)	Natural Gas (Mcf/d)	Average 2011 NRI
Gulf Coast region								
Tertiary Oil Properties								
Phase 1								
Brookhaven	13,552	-	13,552	2.9%	$ 561,962	3,255	-	81.2%
McComb Area	6,540	-	6,540	1.4%	265,354	1,997	-	79.9%
Mallalieu	8,033	-	8,033	1.7%	300,810	2,693	-	78.0%
Other	6,667	-	6,667	1.4%	273,064	3,026	-	69.0%
Phase 2								
Heidelberg	31,096	-	31,096	6.7%	930,408	3,448	-	84.7%
Eucutta	8,720	-	8,720	1.9%	367,952	3,121	-	83.2%
Soso	6,291	-	6,291	1.4%	234,858	2,347	-	77.2%
Martinville	988	-	988	0.2%	24,465	462	-	77.2%
Phase 3 (Tinsley)	31,325	-	31,325	6.8%	1,415,835	6,743	-	80.1%
Phase 4 (Cranfield)	7,628	-	7,628	1.7%	343,077	1,123	-	77.9%
Phase 5 (Delhi)	26,805	-	26,805	5.8%	1,020,302	2,739	-	76.3%
Phase 8 (Oyster Bayou)(3)	-	-	-	0.0%	-	5	-	87.5%
Total Tertiary Oil Properties	147,645	-	147,645	31.9%	5,738,087	30,959	-	78.8%
Non-Tertiary Properties								
Conroe	14,589	22,624	18,359	4.0%	338,168	2,336	2,765	81.2%
Heidelberg	9,880	47,650	17,821	3.9%	373,661	2,239	8,343	76.8%
Citronelle	7,490	-	7,490	1.6%	160,852	991	-	63.5%
Hastings	7,100	-	7,100	1.5%	258,655	1,131	7	82.6%
Other(4)	9,151	29,559	14,078	3.1%	334,453	2,440	10,622	15.7%
Total Non-Tertiary Properties	48,210	99,833	64,848	14.1%	1,465,789	9,137	21,737	36.8%
Total Gulf Coast region	195,855	99,833	212,493	46.0%	7,203,876	40,096	21,737	62.4%
Rocky Mountain region								

Non-Tertiary Properties								
Cedar Creek Anticline	63,762	12,923	65,916	14.3%	1,342,444	8,736	1,393	66.7%
Bakken	78,753	90,618	93,856	20.3%	1,511,622	7,957	4,984	26.3%
Bell Creek	1,966	-	1,966	0.4%	53,092	889	-	85.2%
Paradox	6,234	809	6,369	1.4%	100,311	655	59	11.0%
Riley Ridge(5)	1	414,534	69,090	15.0%	16,889	-	60	43.9%
Other	11,162	6,491	12,244	2.6%	330,905	2,403	1,309	30.8%
Total Rocky Mountain region	161,878	525,375	249,441	54.0%	3,355,263	20,640	7,805	36.0%
Company Total	357,733	625,208	461,934	100.0%	$ 10,559,139	60,736	29,542	51.0%

(1) The reserves were prepared in accordance with Financial Accounting Standards Board Codification ("FASC") Topic 932, Extractive Industries - Oil and Gas, using the average first-day-of-the-month prices for each month during 2011, which for NYMEX oil was $96.19 per Bbl, adjusted to prices received by field, and for natural gas was a Henry Hub cash price of $4.16 per MMBtu, also adjusted to prices received by field.

(2) PV-10 Value is a non-GAAP measure and is different from 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 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. The Standardized Measure was $7.0 billion at December 31, 2011. 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.

(3) We commenced production from Oyster Bayou in December 2011, with the first oil sales occurring at the end of that month. We expect to book initial proved tertiary reserves for the field during 2012. At December 31, 2011, we did not have any tertiary production from our fields in Phases 6 and 7. Phase 6, Citronelle Field, will require an extension to the Free State CO2 Pipeline or another pipeline, depending on the ultimate CO2 source for this field, the timing of which is uncertain. Phase 7, Hastings Field, is currently being injected with CO2, with first tertiary oil response in early 2012.

(4) Includes certain non-core Gulf Coast properties scheduled to be sold during the first quarter of 2012. See Note 14, Subsequent Events, to the Consolidated Financial Statements. These assets had proved reserves of 6,369 MBOE at December 31, 2011.

(5) The PV-10 Value of oil and natural gas properties associated with Riley Ridge does not include the discounted future net revenues associated with the Company's right to extract and sell the helium on behalf of the U.S. government, which we estimate to be $124.5 million at December 31, 2011.

Enhanced Oil Recovery Overview. CO2 used in EOR is one of the most efficient tertiary recovery mechanisms for producing crude oil. The CO2 acts somewhat like a solvent, mixing with the oil and ultimately freeing the oil from the formation as the CO2 passes through reservoir rock. CO2 tertiary floods are unique in that they require large volumes of CO2. To our knowledge, the location of large quantities of natural CO2 in the United States is limited to a few geological basins.

While enhanced oil recovery projects utilizing CO2 may not be considered a new technology, we apply several concepts we have learned over the years to fields to improve and increase sweep efficiency within the reservoirs, which include: (1) well evaluation methods, (2) CO2 injection conformance, (3) new completion techniques, (4) varied operating equipment and operating conditions, and (5) application of intense reservoir management and production techniques. We began our CO2 operations in August 1999, when we acquired Little Creek Field, followed by our acquisition of Jackson Dome CO2 reserves and the NEJD pipeline in 2001. Based upon our success at Little Creek and the ownership of the CO2 reserves, we began to transition our capital spending and acquisition efforts to focus a greater percentage on CO2 EOR and, over time, transformed our strategy to focus almost exclusively on CO2 EOR projects (with the exception of the Bakken properties since 2010). Today, our asset base essentially consists of tertiary oil projects, future tertiary oil projects and the Bakken oil shale play. We believe our investments and knowledge gained give us a strategic and competitive advantage in the areas in which we operate.

Our tertiary operations have grown so that approximately 32% of our proved reserves at December 31, 2011 are proved tertiary oil reserves; approximately 47% of our forecasted 2012 production is expected to come from tertiary oil operations (on a BOE basis); and approximately 62% of our 2012 planned capital expenditures are related to our tertiary oil operations. At year-end 2011, the proved oil reserves in our tertiary recovery oil fields had an estimated PV-10 Value of approximately $5.7 billion, using 12-month first-day-of-the-month unweighted average NYMEX pricing of $96.19 per Bbl. In addition, there are significant probable and possible reserves at several other fields for which tertiary operations are under way or planned. Although the up-front cost of infrastructure is greater than in conventional oil recovery, we believe tertiary recovery has several favorable, offsetting and unique attributes including: (1) it has a lower risk, as we are operating oil fields that have significant historical production and reservoir and geological data, (2) our investments provide a reasonable rate of return at relatively low oil prices (we estimate our economic break-even point on a per-barrel basis before corporate-related overhead and expenses on these projects at current oil prices is in the $40 per barrel range, depending on the specific field and area), and (3) we have limited competition for this type of activity in our geographic regions.

Our Gulf Coast region is more fully developed than our Rocky Mountain region, as we have been expanding and conducting EOR operations in our Gulf Coast region for over 12 years. In the Gulf Coast region, we own the only significant natural sources of CO2 known to us, and these large volumes of CO2 have allowed us to significantly grow our production in that region. In addition to the sources of CO2 we currently have, we are pursuing anthropogenic (man-made) sources of CO2 to use in our tertiary operations, which we believe will not only help us recover additional oil, but will provide an economical way to sequester CO2. We refer to our Gulf Coast tertiary recovery operations by labeling our operating areas or groups of fields as Phases:

- Phase 1 is in southwest Mississippi and includes several fields along our 183-mile NEJD CO2 Pipeline, including the current tertiary fields of Little Creek, Mallalieu, McComb, Brookhaven and Lockhart Crossing;

- Phase 2, which began with the early 2006 completion of the Free State CO2 Pipeline to east Mississippi, currently includes Eucutta, Soso, Martinville and Heidelberg Fields;

- Phase 3, which includes Tinsley Field located northwest of Jackson, Mississippi, was acquired in January 2006 and is serviced by the Delta CO2 Pipeline;

- Phase 4 includes Cranfield and Lake St. John Fields, two fields near the Mississippi/Louisiana border located west of the Phase 1 fields, of which only Cranfield is currently an active tertiary flood;

- Phase 5 is Delhi Field, a Louisiana field we acquired in 2006, located southwest of Tinsley Field, from which our first tertiary oil response occurred during early 2010;

- Phase 6 is Citronelle Field in southwest Alabama, another field acquired in 2006, which will require an extension to the Free State CO2 Pipeline or another pipeline depending on the ultimate CO2 source for this field, the timing of which is uncertain at this time;

- Phase 7 is Hastings Field in southeast Texas, a field we purchased in February 2009, where we commenced CO2 injections during December 2010 in conjunction with placing the final leg of the Green Pipeline into service and where we had first tertiary oil response in early 2012;

- Phase 8 primarily includes Oyster Bayou Field in southeast Texas, acquired in 2007, where we initiated CO2 injections in June 2010 and where we had our first tertiary oil response during December 2011; and

- Phase 9 is Conroe Field, a field we purchased in December 2009, which will require construction of an additional CO2 pipeline to connect the field to the Green Pipeline in southeast Texas.

Through December 31, 2011, we have invested a total of $2.7 billion in tertiary fields in our Gulf Coast region (including allocated acquisition costs and amounts assigned to goodwill) and have recovered all of these costs, with excess net cash flow (revenue less operating expenses and capital expenditures, excluding pipeline-related capital expenditures) of $428 million. Of this total invested amount, approximately $639.9 million (24%) was spent on fields that did not have appreciable proved reserves at December 31, 2011. The proved oil reserves in our Gulf Coast tertiary oil fields have a year-end 2011 PV-10 Value of $5.7 billion, using the first-day-of-the-month 12-month unweighted average NYMEX pricing during calendar 2011 of $96.19 per Bbl. These amounts do not include the capital costs or related depreciation and amortization of our CO2-producing properties or CO2 pipelines, but do include CO2 source field lease operating costs and transportation costs. Excluding the Green Pipeline, which currently does not service any fields with proved tertiary oil reserves, we have invested a total of $892.2 million in CO2 assets in the Gulf Coast region.

We acquired assets in the Rocky Mountain region as part of the Encore Merger, and as such, we have significantly fewer oil fields and CO2 pipeline infrastructure in that region, although we are aggressively developing both. We currently have three fields in the Rocky Mountain region that we plan to flood with CO2: Bell Creek Field, Grieve Field and Cedar Creek Anticline. We have contracted to purchase CO2 from the Lost Cabin gas plant in central Wyoming and are currently constructing the Greencore pipeline to deliver CO2 from the gas plant to our Bell Creek Field. We currently plan to begin injection of CO2 at Bell Creek Field in late 2012 or early 2013. Our Riley Ridge acquisition in 2010 and 2011 also provided us a large source of natural CO2 for our currently planned and future potential projects in the area.

Gulf Coast Region

CO2 Sources

Jackson Dome. Our Gulf Coast CO2 source, Jackson Dome, located near Jackson, Mississippi, was discovered during the 1970s while being explored for hydrocarbons. This significant and relatively pure source of CO2 (98% CO2) is the only significant deposit of CO2 in the United States east of the Mississippi River known to us, and we believe that it provides us a significant strategic advantage in the acquisition of other properties in Mississippi, Louisiana and Texas that could be further exploited through tertiary recovery.

We acquired Jackson Dome in February 2001 for $42 million, a purchase that gave us ownership and control of the NEJD CO_2 pipeline. This acquisition provided the platform to significantly expand our CO_2 tertiary recovery operations by assuring that CO_2 would be available to us on a reliable basis and at a reasonable and predictable cost. Since February 2001, we have acquired two and drilled 26 CO_2-producing wells, significantly increasing our estimated proved Gulf Coast CO_2 reserves from approximately 800 Bcf at the time of acquisition to approximately 6.7 Tcf as of December 31, 2011. These proved reserves are nearly sufficient to provide all of the CO_2 for our existing and currently planned phases of operations in the Gulf Coast, including several fields we own and plan to flood that do not have proven tertiary reserves. The CO_2 reserve estimates are based on a gross working interest of the CO_2 reserves, of which Denbury's net revenue interest is approximately 5.3 Tcf and is included in the evaluation of proved CO_2 reserves prepared by our outside reserve engineer, DeGolyer and MacNaughton. 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 Denbury's tertiary recovery programs and for industrial users who are customers of Denbury and others, as Denbury is responsible for distributing the entire CO_2 production stream.

In addition to the proved reserves, we estimate that we have an additional 2.5 Tcf of probable CO_2 reserves at Jackson Dome. The majority of our probable reserves at Jackson Dome are located in structures that have been drilled and tested in the area but are not currently capable of producing because the original well is plugged; they are located in fault blocks that are immediately adjacent to fault blocks with proved reserves; they are in undrilled structures where we have sufficient subsurface data, and seismic and geophysical attributes that provide a high degree of certainty that CO_2 is present; or they are reserves associated with increasing the ultimate recovery factor from our existing reservoirs with proved reserves. As of December 31, 2011, there have been 13 structures drilled within the Jackson Dome area and only one has not been productive. This success rate, coupled with our seismic control across the undrilled structures, provides us with a high degree of certainty that additional CO_2 reserves will be developed.

Although our current proved and potential CO_2 reserves are quite large, 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 continued our efforts by evaluating our 451 square miles of 3D seismic that we have recorded over the past several years. We anticipate drilling four wells during 2012, three of which are planned development wells and are intended to increase productive capacity, and one of which is an exploratory step-out well that is targeting additional reserves as well as increased flow rate. During 2011, we drilled three CO_2 wells and started the drilling of an exploration CO_2 well on a new structure identified by our seismic program. Two wells were drilled at Gluckstadt Field and one well at the DRI Dock Field. The well at DRI Dock field was determined to be non-commercial and was not completed. In February 2012, we completed the drilling of the exploration well and determined that it was not successful. 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.

In addition to using CO_2 for our Gulf Coast tertiary operations, we sell CO_2 to third-party industrial users under long-term contracts and have three CO_2 volumetric production payment contracts (“VPPs”). Approximately 91% of our average daily CO_2 production in 2011, 87% in 2010 and 87% in 2009 was used in our tertiary recovery operations on our own behalf and on behalf of other working interest owners in our enhanced recovery fields, with the balance delivered to third-party industrial users. During 2011, we sold an average of 89 MMcf/d of CO_2 to commercial users, and we used an average of 920 MMcf/d for our tertiary activities. We are continuing to increase our CO_2 production, which averaged 1,024 MMcf/d during the fourth quarter of 2011, a 5% increase over the fourth quarter of 2010 CO_2 production levels. We estimate that our planned 2012 tertiary operations will require additional CO_2 deliverability, and we currently plan to increase volumes through new drilling in the Gluckstadt Field, along with the addition or modification of certain facilities and pipelines required to deliver the CO_2 to the appropriate oil fields.

Gulf Coast Anthropogenic CO_2 Sources. In addition to our natural source of CO_2, we have entered into long-term contracts to purchase man-made CO_2 from six proposed plants or sources in the Gulf Coast region that will emit large volumes of CO_2. Two of these six projects are currently under construction with estimated completion dates in 2013 and 2014. We estimate these two sources will supply approximately 165 MMcf/d of CO_2 to our EOR operations, although under certain circumstances they could provide up to 270 MMcf/d of CO_2. If the remaining four plants were to also be built, we currently estimate these additional CO_2 sources could potentially provide us with aggregate CO_2 volumes of approximately 640 MMcf/d to 1,350 MMcf/d. Construction of the remaining four plants is contingent on the satisfactory resolution of various matters, including financing. While it is not likely that all four of these plants will be constructed, there are other plants currently being planned that could provide us additional anthropogenic CO_2. We are in ongoing discussions with several of these other potential sources.

In addition to the potential anthropogenic CO_2 sources located in the Gulf Coast, we have entered into long-term contracts to purchase man-made CO_2 from four proposed plants in the Midwest (Illinois, Indiana and Kentucky). Any CO_2 obtained as a result of these projects would most likely be transported to and utilized by our tertiary oil fields in the Gulf Coast region. Construction has not yet commenced on these four projects, which is conditioned, in each case, on Denbury’s ability to justify the construction of the proposed Midwest CO_2 pipeline system. Additionally, at December 31, 2011, two of the proposed Midwest facilities have been unable to meet a critical contractual obligation; thus, we are evaluating these projects to determine if we should extend the time for the facility to meet the contractual obligation. The remaining two proposed plants are actively working to secure the necessary permits and financing to allow them to commence construction. In one potential scenario, we are considering combining the CO_2 pipeline and plant in a joint venture, which would allow us to seek financing on a combined basis, and may include potential loan guarantees from the Department of Energy. This would give us a minority interest in the total project and potentially reduce our required out-of-pocket capital expenditures. See Off-Balance Sheet Agreements – Commitments and Obligations in Management’s Discussion and Analysis of Financial Condition and Results of Operations for a discussion of CO_2 purchase commitments.

In addition to 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. 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 the proposed gasification plants, but such volumes may still be attractive if the source is located near our CO_2 pipelines. The capture of CO_2 could also be influenced by potential federal legislation, which could impose economic penalties for the emission of CO_2. We believe that we are a likely purchaser of CO_2 produced in our areas of operation because of the scale of our tertiary operations, our CO_2 pipeline infrastructure and our large natural sources of CO_2, which can act as a swing CO_2 source to balance CO_2 supply and demand.

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 source. Since 2001 we have constructed an additional 685 miles of CO_2 pipelines that give us the ability to deliver CO_2 to our fields throughout the Gulf Coast. As of December 31, 2011, we either own, or control through long-term financing leases, approximately 864 miles of CO_2 pipelines in the Gulf Coast region. In addition to the NEJD CO_2pipeline, the major pipelines are the Free State Pipeline (90 miles), the Delta Pipeline (110 miles) and the Green Pipeline (325 miles).

In December 2010 we completed the final construction of the Green Pipeline that allowed the first CO_2 injection into the Hastings Field, located near Houston, Texas. The completion of the Green Pipeline 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, all CO_2 flowing in the Green Pipeline is delivered from the Jackson Dome area, but we expect to transport and deliver both natural and anthropogenic CO_2 volumes in the future as the anthropogenic sources are built and begin deliveries to the system.

Gulf Coast Tertiary Properties

Phase 1. Phase 1 includes several fields along our NEJD CO2 pipeline, which runs through southwest Mississippi and into Louisiana. This phase includes some of our most mature CO2 floods, including our initial CO2 field, Little Creek, as well as five other areas (Mallalieu, McComb, Smithdale, Brookhaven and Lockhart Crossing). These fields accounted for approximately 35% of our total 2011 CO2 EOR production. These fields have been producing for some time, and their production is generally on decline.

Since Phase 1 is our most mature phase, most of the development work is complete in this area; however, there are some additional areas at McComb, Brookhaven and Little Creek that we currently plan to develop, the timing of which is largely dictated by the current CO2 recycle facility at each field. As these fields have matured, we have experimented with a variety of techniques to maximize the recovery of oil from these reservoirs, gathering knowledge that we will utilize in all areas of our EOR operations. All of the techniques we are employing are intended to improve the overall sweep efficiency in the formation and hence maximize production. Due to the lower viscosity of CO2 when compared to oil, CO2 will tend to follow the path of least resistance. This may result in high producing gas-oil ratios (“GORs”) sooner than anticipated. We have experimented with various techniques such as cement squeezes (injection and producing wells), chemical squeezes, perforation design and operating pressure controls. Each one of these processes has had some success and will be utilized in the future as appropriate. Our best results to date have been utilizing water-alternating gas (“WAG”) injections, where water is substituted for the CO2 for a given volume and then CO2 is injected behind the water. We have seen multiple patterns respond to the WAG cycles, and we continue to institute the WAG cycles in new patterns as the need arises. The WAG process is currently being used to increase the recovery at fields like Little Creek, our most mature field, where we have already recovered a majority of the forecasted oil, and in fields like Brookhaven, where we have seen certain areas produce high GORs sooner than anticipated. We intend to utilize the techniques that prove successful in Phase 1 in our other phases.

From inception through December 31, 2011, we have recovered all our costs in Phase 1 and the excess net cash flow (revenue less operating expenses and capital expenditures, including the acquisition costs) from this Phase was $1.1 billion. As of December 31, 2011, the estimated PV-10 Value of our Phase 1 properties was $1.4 billion.

Phase 2. Phase 2 includes Eucutta, Soso and Martinville fields, where there has been tertiary oil production for several years, and Heidelberg Field, where we started injecting CO2 in December 2008. Unlike the majority of fields in our other Phases, fields in Phase 2 typically contain multiple reservoirs that are amenable to CO2 EOR. Eucutta, Soso and Martinville fields are mostly developed in the reservoir(s) under flood at the present time. All three fields were initiated in 2006 following completion of the Free State Pipeline. Much like the initial Phase 1 fields, we continue to monitor and modify various patterns, operating conditions and CO2 injections in an attempt to improve the oil recovery from these fields. Based on the performance to date, we expect to recover at least 17% of the original oil in place at these three fields with EOR.

In 2008, we began CO2 injections at Heidelberg Field, which consists of an East and West Unit. Construction of the CO2 facility, connecting pipeline and well work commenced on the West Unit during 2008, with our first CO2 injections beginning in December 2008. Our first tertiary oil production response occurred during May 2009. During 2010, we added 19 new injection patterns and expanded the central processing facility. After exceeding our anticipated production levels in 2010, production from the West Unit began to fall short of expectations in 2011. We determined the shortfall was primarily the result of the CO2 not reaching all the targeted zones, broadly described as “conformance issues.” In 2011, we drilled three new wells and modified the injection or production profile in 39 wells to address the conformance issues by redirecting CO2 into previously un-swept intervals in the West Unit. During the fourth quarter of 2011, EOR production at Heidelberg Field averaged 3,728 Bbls/d as compared to 3,422 Bbls/d in the year-ago period. In 2011, we commenced development of our East Unit, which is larger and contains more oil-in-place than the West Unit. During 2011, we added 9 new injection patterns and installed field facilities in the East Unit and expanded the central processing facility used by both the East and West Units. We have budgeted $47 million in 2012 to continue developing the East Heidelberg Unit, including the addition of two injection patterns in the current development and expansion into a previously undeveloped reservoir.

Many of the fields in Phase 2 have multiple reservoirs. We plan to develop these additional reservoirs in the future when well bores become available (the well bores are currently in use by another reservoir) or when the recycle facilities have available capacity. From inception through December 31, 2011, we have recovered all our costs in Phase 2, and the excess net cash flow (revenue less operating expenses and capital expenditures, including the acquisition costs) from this Phase was $298 million. As of December 31, 2011, the estimated PV-10 Value of our Phase 2 properties was $1.6 billion.

Phase 3 (Tinsley). Phase 3, Tinsley Field, was acquired in January 2006 and is the largest oil field in the state of Mississippi and was first developed in the 1930s. As is the case with the majority of fields in Mississippi, Tinsley produces from multiple reservoirs. Our primary target in Tinsley for CO_2 enhanced oil recovery operations is the Woodruff formation, although there is additional potential in the Perry sandstone and other smaller reservoirs. We initiated limited CO_2 injections in January 2007 through a previously existing 8-inch pipeline, but replaced the use of the 8-inch line in 2008 with the completion of the 24-inch Delta Pipeline to Tinsley. We had our first tertiary oil production from Tinsley Field in April 2008. As of December 31, 2011, we have completed the development of the West Fault Block and the majority of the East Fault Block.

In 2011, we focused on developing the southern half of the East Fault Block. As we were expanding the CO_2 flood into this area, we found that multiple wells, many dating back to the 1940s and 1950s, had been improperly plugged and abandoned by prior operators and did not have sufficient cement in them. Without proper cement plugs in place, we were unable to confine the CO_2 injection into the specific target zones. As a result, we had to stop injecting CO_2 into several patterns in Tinsley, reduce the reservoir pressure in those patterns and work over approximately 28 wells to properly plug them. We are completing the needed well work and are restarting injections in impacted patterns during the fourth quarter of 2011 and first quarter of 2012. Reducing the CO_2 injections lowered our previously anticipated production growth from Tinsley in 2011 and pushed back our 2012 production growth in the area to the second half of the year. These events have not changed our overall expectations of recovery for Tinsley.

In 2012, 2013 and 2014, our expected development will focus on the Northern Fault Block at Tinsley, all in the Woodruff reservoir. The Perry sandstone and the other smaller reservoirs will likely be developed after the Woodruff. During the fourth quarter of 2011, the average tertiary oil production was 6,338 Bbls/d as compared to 6,614 Bbls/d in the year-ago period. Tinsley Field produced an additional 269 Bbls/d from non-CO_2 operations during the fourth quarter of 2011 compared to 291 Bbls/d in the year-ago period.

From inception through December 31, 2011, we have recovered all our costs in 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 $4 million. As of December 31, 2011, the estimated PV-10 Value of our Phase 3 property was $1.4 billion.

Phase 4 (Cranfield). Phase 4 includes Cranfield, where we began CO_2 injection operations during July 2008 and had our first oil production response in the first quarter of 2009. Phase 4 also includes Lake St. John Field, a project currently scheduled to commence within the next several years following a proposed crossing of the Mississippi River with our CO_2 pipeline. Both Phase 4 fields are located near the Mississippi/Louisiana border, near Natchez, Mississippi.

We began development of Cranfield during 2008, commenced injections into the Lower Tuscaloosa reservoir in the third quarter of 2008, and had our first tertiary oil production in the first quarter of 2009. Development of Cranfield will continue over the next several years with the addition of two to three patterns each year. During 2012, we plan to spend approximately $9 million to develop three patterns in the field. We are participating with the Bureau of Economic Geology at the University of Texas as it studies CO_2 injection and sequestration at Cranfield, to better define and understand the movement of CO_2 through the Lower Tuscaloosa reservoir.

From inception through December 31, 2011, we had not yet recovered our investment in this field and the remaining net investment to be recovered (revenue less operating expenses and capital expenditures, including the acquisition cost) from Cranfield was $83 million. As of December 31, 2011, the estimated PV-10 Value of our Phase 4 property was $343.1 million.

Phase 5 (Delhi). Phase 5 is Delhi Field, a Louisiana field located southwest of Tinsley Field and east of Monroe, Louisiana. During May 2006, we purchased Delhi for $50 million, plus a 25% reversionary interest to the seller after we achieve $200 million in net operating income. 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 to Delhi. First tertiary production occurred at Delhi Field in March 2010. Early performance data is indicating that Delhi Field is acting as a miscible flood instead of a near-miscible flood as we originally modeled, which if true and if it continues, should positively affect our results. Production from Delhi in the fourth quarter of 2011 averaged 3,778 Bbls/d, up from 703 Bbls/d in the year-ago period. During 2012, we plan to spend approximately $64 million to develop three patterns and to construct additional facilities at Delhi Field.

From inception through December 31, 2011, we had not yet recovered our investment in this field, and the remaining investment to be recovered (revenue less operating expenses and capital expenditures, including the acquisition cost) from Delhi Field was $199 million. As of December 31, 2011, the estimated PV-10 Value of our Phase 5 property was $1.0 billion.

Future Gulf Coast Tertiary Properties without Proved Tertiary Reserves or Tertiary Production at December 31, 2011

Phase 6 (Citronelle). Phase 6 is Citronelle Field in Southwest Alabama, another field acquired in 2006. Citronelle Field will require an extension to the Free State CO2 Pipeline or a man-made source of CO2 in order to commence this project, the timing of which is uncertain.

Phase 7 (Hastings). Phase 7 is Hastings Field, a strategically significant property in southeast Texas. We acquired a majority interest in this field in February 2009 for approximately $247 million. Under the terms of the option agreement, Venoco, Inc. (“Venoco”), the seller, retained a 2% override and reversionary interest of approximately 25% following payout, as defined in the option agreement. During 2010 we acquired the 2% override from Venoco for approximately $22.3 million. During the fourth quarter of 2011, non-tertiary production from Hastings Field averaged 1,094 BOE/d as compared to 1,474 BOE/d in the year-ago period. Conventional proved reserves at Hastings Field as of December 31, 2011 were approximately 7.1 MMBOE.

We believe the West Hastings Unit has the second-largest CO2 EOR reserve potential in our Gulf Coast inventory. Due to the vertical oil column that exists in the field, we are developing the Frio reservoir in multiple vertically segregated CO2 EOR projects. Each vertical interval will have dedicated CO2 injection wells and dedicated producing wells. We initiated CO2 injection in the West Hastings Unit during December 2010 upon completion of the construction of the Green Pipeline. We began producing EOR oil from the Hastings Field in late January 2012, and we expect to book initial proved tertiary reserves for the field by the end of 2012. In 2012, we expect to invest $66 million to continue developing the West Hastings Unit, including the development of additional patterns and expanding the processing facilities. Significant additional capital expenditures will be required over several years to fully develop the field.

Phase 8 (Oyster Bayou). Phase 8, which we acquired in 2007, consists of two fields located in southeast Texas on the east side of Galveston Bay. The Oyster Bayou and Fig Ridge Fields are located in close proximity to each other. We acquired a majority interest in Oyster Bayou Field and a relatively small interest in Fig Ridge Field. Oyster Bayou Field was unitized in the spring of 2010 and we began CO2 injections there in June 2010. Oyster Bayou Field is somewhat unique when compared to our other CO2 EOR projects because the field covers a relatively small area of 3,912 acres and will be developed in essentially one stage. We commenced production from Oyster Bayou Field in December 2011, with the first oil sales occurring at the end of that month. We expect to book initial proved tertiary reserves for the field by the end of 2012. In 2012, we expect to invest $35 million to complete several patterns and expand facilities in Oyster Bayou Field.

The other field in Phase 8 is the Fig Ridge Field. Due to our lack of majority interest in this field, it is uncertain if, or when, we will flood Fig Ridge Field.

Phase 9 (Conroe). Phase 9 is Conroe Field, our largest potential tertiary flood in the Gulf Coast region, located north of Houston, Texas. We acquired a majority interest in this field in 2009 for approximately $271 million in cash and 11,620,000 shares of Denbury common stock for a total aggregate value of $439 million. The acquired Conroe Field interests had estimated proved conventional reserves of approximately 18.4 MMBOE on December 31, 2011, nearly all of which are proved developed. During the fourth quarter of 2011, production at Conroe Field averaged 2,587 BOE/d net to our acquired interest. Given the size of the Conroe Field of approximately 20,000 acres, the volume of CO2 that could be injected is quite sizable, much larger than any field we have developed to date. Therefore, the pace of development will partly be dictated by the amount of available CO2.

A pipeline must be constructed so that CO2 can be delivered to Conroe. This pipeline, which is planned as an extension of our Green Pipeline, is preliminarily estimated to cover 85 miles at a cost of between $165 million to $190 million. Through 2013, we will determine the pipeline path, initiate the acquisition of rights-of-way, and engineer and design the pipeline while refining and finalizing our CO2 EOR plan for Conroe. Construction of the pipeline is expected to occur in 2014, with start-up and commissioning by the end of that year.

Non-Tertiary Oil and Natural Gas Properties in the Gulf Coast

We have been active in East Mississippi since Denbury was founded in 1990 and are by far the largest oil producer in the basin and the state. Conventional or non-tertiary production during the fourth quarter of 2011, excluding non-core assets to be disposed, averaged approximately 4,746 BOE/d from this area (7% of our total continuing production), and we had proved reserves of 24.3 MMBOE as of December 31, 2011 (5% of our Company total). Since we have generally owned these East Mississippi properties longer than properties in our other regions, they tend to be more fully developed. Production from our conventional and secondary recovery operations in our East Mississippi fields, excluding non-core assets to be disposed, has been gradually declining, as expected, over the last three years, averaging 8,343 BOE/d during 2009, 6,505 BOE/d during 2010 and 5,486 BOE/d during 2011. During 2011, we invested very little capital in these assets. In January 2012, we entered into an agreement to sell certain non-core properties in this area for $155 million, before customary closing adjustments, and expect to close the sale in late February 2012.

The largest field in the region is the Heidelberg Field, which for the fourth quarter of 2011 produced an average of 3,129 BOE/d of conventional or non-tertiary production. This compares to 4,206 BOE/d in the year-ago period, with most of the decline in production occurring in the Selma Chalk. Heidelberg Field was acquired from Chevron in December 1997. Most of the past and current production comes from the Eutaw, Selma Chalk and Christmas sands at depths from 3,500 feet to 5,000 feet. The majority of the conventional oil production at Heidelberg Field is from waterflood units that produce from the Eutaw formation (at approximately 4,400 feet). We have converted all of the waterflood units in West Heidelberg to CO2 EOR and, as described previously above, are in the process of converting the East Heidelberg waterflood units to CO2 EOR. Heidelberg also produces natural gas from the Selma Chalk, which was a fairly active area of development for us prior to 2009. The Selma Chalk is a natural gas reservoir at around 3,700 feet that is developed with horizontal wells and hydraulic fracturing. The Selma Chalk is estimated to contain 71.6 Bcf of proved natural gas reserves as of December 31, 2011. Natural gas production from the Selma Chalk was 13.4 MMcf/d during the fourth quarter of 2011, as compared to 16.3 MMcf/d in the year-ago period. The decline in production is due to a decrease in drilling activity over the past several years, combined with a rapid decline rate in the Selma Chalk wells.

Rocky Mountain Region

CO2 Sources

Riley Ridge. Our primary future Rocky Mountain CO2 source, Riley Ridge, which is located in southwestern Wyoming, commenced natural gas production in the mid-1980s. The gas composition from Riley Ridge is approximately 65% CO2, 19% natural gas, 5% hydrogen sulfide (H2S), 0.6% helium, and the remainder other gases.

We acquired Riley Ridge in two phases. In October 2010, we acquired a 42.5% non-operated working interest for $132.3 million after closing adjustments. This initial purchase included a 42.5% interest in a gas plant that was under construction and that will separate the helium and natural gas from the gas stream. In August 2011, we acquired the remaining 57.5% working interest in Riley Ridge and the remaining interest in the gas plant. As a result of the second phase of the transaction, we became the operator of the project. The purchase price for the second phase was $214.8 million after closing adjustments, including a $15 million deferred payment to be made at the time the gas plant is operational and meets specific performance conditions. We expect the gas plant to be operational during the second quarter of 2012.

As of December 31, 2011, our interest in Riley Ridge and minor surrounding acreage contained net proved reserves of 415 Bcf of natural gas and 2.2 Tcf of CO2 reserves. The CO2 reserve estimates are based on the gross working interest of the CO2 reserves, in which Denbury's net revenue interest is approximately 1.6 Tcf. The helium reserves at Riley Ridge are owned by the U.S. government; however, we have the right to produce and sell the helium reserves on behalf of the government in exchange for a fee. As of December 31, 2011, we estimate that Riley Ridge contains proved helium reserves of 12.0 Bcf, presented net of amounts to be remitted the U.S. government. In addition, we believe there is significant reserve potential in other acreage surrounding Riley Ridge in which we also own an interest.

The gas plant under construction at Riley Ridge will separate the natural gas and helium from the full well stream and the remaining gases, including CO2, will initially be reinjected into the producing formation until a planned CO2 capture facility and pipeline can be built. We have initiated the engineering and design of the CO2 capture facility, which is estimated to initially capture up to 130 MMcf/d of CO2. In addition to designing the CO2 capture facility, we are preparing development plans for the adjoining acreage, which when fully developed is expected to add 450 MMcf/d to 520 MMcf/d of CO2 (100% working interest), or an estimated total CO2 production from this asset of up to 650 MMcf/d (100% working interest). The development plan to achieve these rates is expected to take up to 10 years. We estimate 2012 capital costs for Riley Ridge at approximately $70 million in order to complete the initial phase of the facilities, drill one producer well and one injector well, build flow lines, and conduct engineering studies on CO2 capture and separation.

Rocky Mountain Anthropogenic CO2 Sources. We have ongoing discussions with and are actively pursuing several sources for anthropogenic CO2 supply in the Rocky Mountain region. We have contracted to purchase CO2 from the Lost Cabin gas plant in central Wyoming and from ExxonMobil's LaBarge facility in southwest Wyoming. The Lost Cabin agreement requires us to purchase as much as 50 MMcf/d of CO2 from the Lost Cabin plant. The purchase requirements also include the construction of the necessary pipeline tie-ins to the gas plant, and compression and metering equipment. In 2011, we completed most of the interconnecting and tie-in work to the gas plant required to capture the CO2. Final engineering design continues; compression, pumps and metering equipment have been ordered; and we expect to complete the plant tie-ins in the first half of 2012 and then install the required compression and metering equipment in the second half of 2012. All work is scheduled to be completed by the fourth quarter of 2012 to capture, compress and deliver the CO2 into the Greencore Pipeline. We estimate our 2012 capital investment in the Lost Cabin gas plant infrastructure will be $50 million. The agreement with ExxonMobil requires us to purchase 30 MMcf/d of CO2, with an option to purchase up to 50 MMcf/d of CO2 from ExxonMobil's LaBarge facility. We intend to utilize the CO2 to flood Grieve Field and expect to begin taking deliveries during the second half of 2012.

During the first quarter of 2011, we finalized and entered into a long-term supply contract to purchase anthropogenic CO2 from a proposed plant in southeastern Wyoming. We estimate the proposed plant will initially supply approximately 100 MMcf/d, and potentially up to 200 MMcf/d, of CO2 for our enhanced oil recovery operations in Wyoming and Montana. We expect to begin taking delivery of this CO2 in approximately four years following commencement of construction. The purchase price of CO_2 will fluctuate based on changes in the price of oil. As is the case with all of our long-term supply contracts to purchase CO_2, the agreement is subject to various contingencies, and completion of the plant is contingent upon securing debt financing and equity commitments, along with receipt of all necessary consents and approvals.

Greencore Pipeline. The 20-inch Greencore Pipeline in Wyoming is the first CO_2 pipeline constructed by Denbury in the Rocky Mountain region. As currently planned, the pipeline will eventually connect our Lost Cabin Plant CO_2 source to the Cedar Creek Anticline in eastern Montana, and ultimately connect our CO_2 source at Riley Ridge (see Rocky Mountain CO_2 Sources above). The initial 232-mile section of the Greencore Pipeline will begin at the Lost Cabin gas plant and terminate at our Bell Creek oil field in Montana. This portion of the pipeline will be constructed in two phases: the first 115-mile segment was completed in December 2011, and the second 117-mile segment will commence construction in August 2012 with currently scheduled completion in late 2012. Pipeline completion is expected to coincide with the installation of capture equipment at the Lost Cabin gas plant. We estimate our 2012 capital costs for the Greencore Pipeline will be $135 million.

Future Rocky Mountain Tertiary Properties without Proved Tertiary Reserves or Tertiary Production at December 31, 2011

Grieve Field. In May 2011, Denbury entered into a farm-in agreement, under which we have the right to acquire up to 65% of the working interest in the Grieve Field, located in Natrona County, Wyoming. We estimate that the Grieve project has the potential for recovery of approximately 12 MMBbls of gross oil, or 6.1 MMBbls net to our revenue interest. We are overseeing operations, design, construction and operations of the field. We are contracting for the construction of the CO_2 recycle facility and the required three-mile CO_2 pipeline to deliver CO_2 from an existing CO_2 pipeline to the Grieve Field. We estimate first CO_2 injection at Grieve Field in the third quarter of 2012, with first EOR production estimated in 2014. We plan to invest $39 million in Grieve Field in 2012, primarily to install a three-mile pipeline and to install injection and power infrastructure.

Bell Creek Field. Bell Creek Field is located in southeast Montana. A majority interest was acquired as part of the Encore Merger. Development of the CO2 EOR project at Bell Creek Field was started by Encore. As of December 31, 2011, the majority of the work has involved re-activating wells in the field and injecting additional water into the reservoir to raise reservoir pressure in anticipation of future CO2 injections. The original operator of the field temporarily abandoned wells in such a way as to preserve the mechanical integrity of the wellbore and to minimize the cost of re-entering the wells. We expect to have first CO2 injections in Bell Creek Field upon completion of the Greencore Pipeline in late 2012. We anticipate first tertiary oil production by early 2014. Because the producing reservoir in Bell Creek Field is a sandstone reservoir very similar to our Gulf Coast reservoirs, we expect the CO2 EOR project to perform similarly. Conventional production net to our interest during the fourth quarter of 2011 averaged 840 Bbls/d, as compared to 957 Bbls/d in the year-ago period. Our 2012 capital expenditures to finish well work, install flowlines and shoot 3-D seismic over the first injection stage in Bell Creek Field is estimated to be $18 million.

Cedar Creek Anticline. Cedar Creek Anticline ("CCA") is primarily located in Montana but covers such a large area (approximately 120 miles) that it also extends into North Dakota. CCA is a series of 10 producing oil units, each of which could be considered a field by itself. We acquired our interest in CCA as part of the Encore Merger, and it is currently the largest potential EOR field we own. Production, net to our interest, during the fourth quarter of 2011 from all of the units in CCA averaged 8,858 BOE/d, compared to 9,328 BOE/d in the year-ago period. The conventional proved reserves associated with CCA were 63.8 MMBbls of oil and 12.9 Bcf of gas as of December 31, 2011.

CCA is located approximately 110 miles north of Bell Creek Field, and we expect to ultimately connect this field to our proposed Greencore Pipeline. CCA produces from numerous reservoirs, although the primary reservoir is the Red River formation, which is a series of dolomitic reservoirs that have produced significant amounts of oil. A CO2 pilot project conducted in the South Pine Unit in the mid-1980s demonstrated the potential to produce an additional 18% of the original oil-in-place from the Red River Zone U4 reservoir. We currently forecast beginning tertiary oil production at CCA in 2017. We expect the majority of the capital spending at CCA over the next several years will be invested to modify and expand the existing waterflood operations, upgrade and improve our production handling equipment, and upgrade and improve artificial lift equipment.

Non-Tertiary Oil and Natural Gas Properties in the Rocky Mountain Region

Bakken. The Bakken play in North Dakota and Montana is one of the more active unconventional oil plays in North America. We acquired a significant acreage position in the Bakken play as part of the Encore Merger. At December 31, 2011, we had approximately 200,000 net prospective mineral acres under lease in the Bakken play, down from approximately 275,000 acres at year-end 2010. The reduction was primarily related to our removing the Almond area from our acreage counts after drilling results indicated the area was uneconomic. We conducted an active operated and non-operated drilling program on our Bakken acreage in 2011. During 2011, we operated an average of five drilling rigs on our acreage, and we drilled and completed 30 operated Bakken wells. Fourth quarter 2011 production averaged 11,743 BOE/d, up from 5,193 BOE/d in the fourth quarter of 2010. In addition to the operated wells we drilled during 2011, we also participated in an additional 103 non-operated wells. Our total investment in the Bakken play for 2011 was $435 million, excluding capitalized interest.

The typical Bakken well is horizontally drilled with a 10,000-foot horizontal section that traverses the majority of a two-section, 1,280-acre spacing unit. Where previous smaller spacing units (640 acres or 320 acres) exist, the horizontal section is reduced to approximately 5,000 feet. At the present time, we are seeking regulatory approval to drill seven wells per 1,280-acre spacing unit.

Completion technologies in the Bakken have been evolving and will continue to evolve as operators test new ideas. At the present time, after a well is drilled, the horizontal section is typically hydraulically fractured utilizing 20 to 30 frac stages to complete the well, although other operators have experimented with up to 40 stages. Once all of the stages are pumped, the well is turned to production. The Bakken shale includes two producing intervals over a large portion of the play. The Middle Bakken is the shallower productive interval and is present throughout the entire play. Three Forks is the lower productive interval of the Bakken, but does not cover the entire Bakken play. Given the reservoir characteristics of the Bakken, which is a tight shale, production rates may initially exceed 2,000 BOE/d but thereafter decline rapidly for the first year or two, producing for many years thereafter at a more conventional or slow rate of decline. Denbury is continually refining the completion and hydraulic fracturing designs on wells, as are all operators in the Bakken. Early in the life of the play, many wells were stimulated with a relatively small number of stages, typically fewer than six or eight. We have had success in re-fracturing these early wells and expect to continue to re-frac additional wells during 2012.

Our total estimated capital for our Bakken drilling program in 2012 is approximately $400 million. Of this amount, we intend to spend $245 million to operate an average of four rigs to drill approximately 34 Bakken wells. We currently intend to begin 2012 with six operated rigs and then gradually decline to three rigs by mid-2012. We may eventually decide to retain four rigs in the Bakken if oil prices, and hence operating cash flow, exceed our expectations. Typically, we own a 40% to 100% working interest in our operated wells. Due to our large acreage position, we also participate in numerous non-operated wells in the Bakken. In 2012, we expect to participate in more than 130 non-operated wells at a total net cost of approximately $155 million. We expect working interests in these wells to generally range from 10% to 25%.

Hydraulic Fracturing

We use a hydraulic fracturing process to stimulate production in our Bakken shale and Selma Chalk properties. During 2011, we fracture stimulated 31 operated wells in the Bakken and 4 wells in the Selma Chalk utilizing water-based fluids with no diesel component. In these operations, we are cognizant of environmental laws and continually monitor all of our operations for possible environmental impact. In areas where there is known shallow water flow, Denbury underlines the location with a plastic barrier to prevent any fluids from seeping into the ground water. We utilize metal sided containment walls with plastic underliners around our separation and storage facilities to serve as secondary containment, should a spill incident occur. After the stimulation has been completed and the well is produced, it is common to recover 15% to 30% of the water used for the stimulation. All of the return water is collected onsite in storage tanks, and delivered via water transports to a commercial salt water disposal facility. During 2011, we derived in the range of 10% to 15% of our revenues from properties which have been fracture stimulated at some point in the useful life of the properties.

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, 2011:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Gulf Coast	259,926	215,886	425,691	108,162	685,617	324,048
Rocky Mountain	371,412	280,805	458,890	256,613	830,302	537,418
Total	631,338	496,691	884,581	364,775	1,515,919	861,466

Our net undeveloped acreage that is subject to expiration over the next three years, if not renewed, is approximately 16% in 2012, 19% in 2013 and 4% in 2014.

Productive Wells

The following table sets forth our gross and net productive oil and natural gas wells as of December 31, 2011:

	Producing Oil Wells		Producing Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Operated Wells:						
Gulf Coast region	1,249	1,155.0	251	229.8	1,500	1,384.8
Rocky Mountain region	859	735.4	3	2.4	862	737.8
Total	2,108	1,890.4	254	232.2	2,362	2,122.6
Non-Operated Wells:						
Gulf Coast region	66	3.0	221	1.4	287	4.4
Rocky Mountain region	504	65.1	2	0.1	506	65.2
Total	570	68.1	223	1.5	793	69.6
Total Wells:						
Gulf Coast region	1,315	1,158.0	472	231.2	1,787	1,389.2
Rocky Mountain region	1,363	800.5	5	2.5	1,368	803.0
Total	2,678	1,958.5	477	233.7	3,155	2,192.2

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Drilling Activity

The following table sets forth the results of our drilling activities over the last three years. As of December 31, 2011, we had 27 gross (5.5 net) wells in progress.

	Year Ended December 31,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:(1)						
Productive(2)	-	-	-	-	1	1.0
Non-productive(3)	1	0.7	-	-	-	-
Development Wells:(1)						
Productive(2)	221	116.6	127	62.8	23	16.6
Non-productive(3)(4)	-	-	-	-	-	-
Total	222	117.3	127	62.8	24	17.6

(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 2011, 2010 and 2009, an additional 46, 41 and 20 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, 2011, 2010 and 2009:

	Year Ended December 31,		
	2011	2010	2009
Net sales volume:			
Gulf Coast region			
Oil (MBbls)	14,635	14,657	13,487
Natural gas (MMcf)	7,934	22,271	24,851
Total Gulf Coast region (MBOE)	15,957	18,369	17,629
Rocky Mountain region			
Oil (MBbls)	7,534	7,212	-
Natural gas (MMcf)	2,849	6,220	-
Total Rocky Mountain region (MBOE)	8,009	8,249	-
Total Company (MBOE)	23,966	26,618	17,629

Average sales price:				
	Gulf Coast region			
	Oil (per Bbl)	$ 105.23	$ 78.35	$ 57.75
	Natural gas (per Mcf)	4.31	4.56	3.54
	Rocky Mountain region			
	Oil (per Bbl)	$ 89.93	$ 71.12	$ -
	Natural gas (per Mcf)	6.12	4.90	-
	Total Company			
	Oil (per Bbl)	$ 100.03	$ 75.97	$ 57.75
	Natural gas (per Mcf)	4.79	4.63	3.54

	Year Ended December 31, 2011	2010	2009
Average production cost (per BOE sold):(1)			
Gulf Coast region	$ 24.51	$ 19.94	$ 17.85
Rocky Mountain region	14.52	12.61	-
Total Company	21.17	17.67	17.85

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

PRODUCTION AND UNIT PRICES

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 – Operating Results, included herein.

TITLE TO PROPERTIES

Customarily in the oil and natural gas industry, only a perfunctory title examination is conducted at the time properties believed to be suitable for drilling operations are first acquired. Prior to commencement of drilling operations, a thorough drill site title examination is normally conducted, and curative work is performed with respect to significant defects. Typically, in connection with acquisitions, title reviews are performed on selected higher-value properties. We believe that we have good title to our oil and natural gas properties, some of which are subject to minor encumbrances, easements and restrictions.

SIGNIFICANT OIL AND GAS PURCHASERS AND PRODUCT MARKETING

Oil and gas sales are made on a day-to-day basis under short-term contracts at the current area market price. The loss of any single purchaser would not be expected 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 years ended December 31, 2011 and December 31, 2010, two purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company LLC (43% and 46% in 2011 and 2010, respectively) and Plains Marketing LP (16% and 14% in 2011 and 2010, respectively). For the year ended December 31, 2009, we had two significant purchasers that each accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company LLC (52%) and Hunt Crude Oil Supply Co. (21%).

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 limited transportation options caused by oversubscribed pipelines and market centers that are distant from producing properties. As of December 31, 2011, 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

The quality of our crude oil varies by area, thereby impacting the corresponding price received. As an example, in Heidelberg Field, one of our larger fields, and our other eastern Mississippi non-tertiary properties, our oil production is primarily light to medium sour crude and has historically sold at a significant discount to NYMEX prices. However, during 2011, our light to medium sour crude sold at an average premium of $6.58 per barrel over NYMEX prices. In western Mississippi, the location of our Phase 1 tertiary operations, our oil production is primarily light sweet crude, which historically sold near, or at a modest premium to, NYMEX prices. However, during 2011, our oil production in this area sold for more than $15.00 per barrel over NYMEX prices. The premiums above NYMEX were more pronounced in the second half of 2011 and are attributable to the depressed nature of the West Texas Intermediate ("WTI") market in Cushing, OK (where NYMEX is valued) relative to the other grades of waterborne crude oil (e.g., Louisiana Light Sweet ("LLS"), Poseidon, Mars, Mayan and Brent).

The marketing of our Rocky Mountain region oil production is dependent on transportation through local pipelines to market centers in Guernsey, Wyoming; Clearbrook, Minnesota; and Wood River, Illinois. Shipments on some of the pipelines are oversubscribed and subject to apportionment. We have currently been allocated 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 somewhat greater stability in oil differentials in the area, although recent events resulting in wider than usual differentials in the current markets are expected to remain in place until incremental takeaway capacity comes on line. For the year ended December 31, 2011 the discount for our oil production in the Rocky Mountain region averaged $5.15 per Bbl, compared to $8.35 per Bbl during 2010.

Overall, during 2011, we sold approximately 45% of our production based on the LLS index price, although due to contract provisions we may not realize the full differential; 28% of our production based on NYMEX or WTI Posting plus Argus P+ prices; and 27% based on various other indexes, most of which have also improved relative to WTI, but to a lesser degree.

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. Our gas production in the Rocky Mountain region, like our oil production, is dependent on 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, 2011, we averaged $0.15 per Mcf above NYMEX prices for our Mississippi natural gas production. In the Texas Gulf Coast region, due primarily to its location, the price we received for the year ended December 31, 2011 averaged $0.66 per Mcf above NYMEX prices. The Rocky Mountain region natural gas production 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. Because there are a limited number of gas markets in this region, during 2011 we flared a significant portion of the natural gas produced in this region. The natural gas has a significant component of propane, butanes and other higher-density hydrocarbons, resulting in a measurable natural gas liquids stream. For the year ended December 31, 2011, we averaged $2.09 per Mcf over NYMEX prices for our Rocky Mountain region natural gas production due primarily to the natural gas liquids extracted from the gas stream, improving the net price we receive. In late 2011, we amended the gas sales contracts for our Bakken production to sell the natural gas liquids separately from the dry gas. As a result, sales of natural gas liquids will be included in our oil sales in 2012 and future periods.

Helium Marketing

We expect production to commence at Riley Ridge Field during the second quarter of 2012, at which time we will begin to supply helium to a third party purchaser under a 20-year helium supply arrangement. Helium will be sold under the contract at a price that will fluctuate based on helium deliveries, CPI and other factors over the 20-year term.

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, and CO_2 properties; marketing of oil and natural gas; and obtaining 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. Gathering systems are the only practical method for the intermediate transportation of natural gas. Therefore, competition for natural gas delivery is presented by other pipelines and gas gathering systems. Competition is also presented to a lesser extent by alternative fuel sources, including heating oil and other fossil fuels. Because of the 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.

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 natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. There have also been 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. Higher oil and natural gas prices generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. 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 or restrict our ability to drill those wells and conduct those operations that we currently have planned and budgeted.

FEDERAL AND STATE REGULATIONS

Numerous federal and state 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 this evolving regulatory burden is often difficult and costly, and substantial penalties may be incurred for noncompliance. The following sections describe some specific laws and regulations that may affect us. We cannot predict the impact of these or future legislative or regulatory initiatives.

Management believes that we are in substantial compliance with all laws and regulations applicable to our operations and that continued compliance with existing requirements will not have a material adverse impact on us. The future annual capital cost of complying with the regulations applicable to our operations is uncertain and will be governed by several factors, including future changes to regulatory requirements. However, management does not currently anticipate that future compliance will have a materially adverse effect on our consolidated financial position, results of operations or cash flows.

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 the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these 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. The regulatory burden on the oil and gas industry increases our costs of doing business and, consequently, affects our profitability.

Federal Regulation of Sales Prices and Transportation

The transportation and certain sales of natural gas in interstate commerce are heavily regulated by agencies of the U.S. federal government and are affected by the availability, terms and cost of transportation. In particular, 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 rules and regulations affecting the natural gas industry. Some of FERC's proposals 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. We cannot predict when or if any such proposals might become effective and their effect, if any, on our operations.

Federal Energy and Climate Change Legislation and Regulation

In October 2008, as part of the Emergency Economic Stabilization Act, Congress included a new tax credit for carbon capture and sequestration, including that achieved through enhanced oil recovery, as further modified by the American Recovery and Reinvestment Act of 2009, passed in February 2009. In early 2012, the President signed the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, which updates federal pipeline safety standards, increases penalties for violations, gives the Transportation Department authority for new damage prevention and incident notification, and directs the Transportation Department to prescribe new minimum safety standards for CO2 pipelines, which could affect our operations and the costs thereof. In future periods, Congress may create new incentives for alternative energy sources and may also consider legislation to reduce emissions of CO2 or other gases. If enacted, such legislation could impose a tax or other economic penalty on the production of fossil fuels that, when used, ultimately release CO2, and could reduce the demand for and uses of oil, gas and other minerals and/or increase the costs incurred by the Company in its exploration and production activities. The Environmental Protection Agency ("EPA") has promulgated regulations requiring permitting for release of certain greenhouse gases, along with requirements for wells used for geologic sequestration. At the same time, legislation to reduce the emissions of CO2 or other gases could also create economic incentives for technologies and practices that reduce or avoid such emissions, including processes that sequester CO2 in geologic formations such as oil and gas reservoirs.

Natural Gas Gathering Regulations

State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory-take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Federal, State or Indian Leases

Our operations on federal, state or Indian oil and gas leases, especially those in the Rocky Mountains, 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

Public interest in the protection of the environment has increased dramatically in recent years. Our oil and natural gas production, saltwater disposal operations, injection of CO2, and our 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 fines and sanctions as a result of any violations or liabilities under environmental or other laws. Changes in or more stringent enforcement of environmental laws could also result in additional operating costs and capital expenditures.

Various federal, state and local laws regulating the discharge of materials into the environment or otherwise relating to the protection of the environment, directly impact oil and gas exploration, development and production operations, and consequently may impact our operations and costs. These regulations include, among others, (i) regulations by the EPA and various state agencies regarding approved methods of disposal for certain hazardous and nonhazardous wastes; (ii) the Comprehensive Environmental Response, Compensation, and Liability Act, Federal Resource Conservation and Recovery

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; (iii) the Clean Air Act and comparable state and local requirements, which may result in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations or could result in the imposition of economic penalties on the production of fossil fuels that, when used, ultimately release CO2; (iv) 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; (v) the Resource Conservation and Recovery Act, which is the principal federal statute governing the treatment, storage and disposal of hazardous wastes; (vi) the Endangered Species Act and counterpart state legislation, which protects endangered and threatened species and could include certain species present on our leases, such as the sage grouse, as threatened or endangered; and (vii) state regulations and statutes governing the handling, treatment, storage and disposal of NORM.

Management believes that we are in substantial compliance with applicable environmental laws and regulations. Management 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 compliance and regulations could cause significant delays, which may cause our expected production rates and cash flows to be less than anticipated.

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

Internal Controls Over Reserve Estimates

We engage DeGolyer and MacNaughton, an independent petroleum engineering consulting firm located in Dallas, Texas, to prepare our reserve estimates, and we rely on their 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 this consulting firm; 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 35 years of experience in oil and gas reservoir studies and evaluations. Denbury’s Vice President – Reserves and Technology is primarily responsible for overseeing the independent petroleum engineering firm during the process. Our Vice President – Reserves and Technology has a Bachelor of Science degree in Petroleum Engineering and over 20 years of industry experience working with petroleum reserve estimates. The Company’s internal reserve engineering team consists of qualified petroleum engineers who both provide data to the independent petroleum engineer and prepare interim reserve estimates. The internal reserve team reports directly to our Vice President – Reserves and Technology. In addition, the Company’s Board of Directors’ Reserves Committee, on behalf of the Board of Directors, oversees the qualifications, independence, performance and hiring of the Company’s independent petroleum engineering firm and reviews the final report and subsequent reporting of the Company’s oil and natural gas reserves. The Chairman of the Reserves Committee is a Chartered Engineer of Great Britain and received his Bachelor of Science degree in Chemical Engineering from the University of London in 1963.

Oil and Natural Gas Reserves Estimates

DeGolyer and MacNaughton prepared estimates of our net proved oil and natural gas reserves as of December 31, 2011, 2010 and 2009. See the summary of DeGolyer and MacNaughton’s report as of December 31, 2011, included as an exhibit to this Form 10-K. Estimates of reserves were prepared using an average price equal to the un-weighted 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. Our 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 2011, we provided oil and gas reserve estimates for 2010 to the United States Energy Information Agency, which were substantially the same as the reserve estimates included in our Form 10-K for the year ended December 31, 2010.

Our proved nonproducing 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 typically have both proved producing and proved nonproducing reserves.

As of December 31, 2011, our estimated proved undeveloped reserves totaled approximately 201.2 MMBOE, or approximately 44% of our estimated total proved reserves. Our proved undeveloped oil reserves primarily relate to our CO2 tertiary operations (48.2 MMBOE) and Bakken fields (69.9 MMBOE). Our proved undeveloped natural gas reserves are primarily located in our Riley Ridge Field (69.1 MMBOE). We consider the CO2 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 secondary recovery or tertiary recovery operations in fields and reservoirs that historically produced substantial volumes of oil under primary production.

During 2011, we spent approximately $160 million to convert 26.4 MMBOE of proved undeveloped reserves to proved developed reserves. Proved undeveloped reserves were converted primarily through the expansion of our tertiary floods at Delhi and Tinsley fields (19.8 MMBOE) and through additional drilling in the Bakken (5.5 MMBOE). The offsetting 67.2 MMBOE increase in our proved undeveloped reserves from December 31, 2010 to December 31, 2011 is primarily due to the acquisition of Riley Ridge Field (36.8 MMBOE) and new proved undeveloped reserves identified as a result of additional drilling in the Bakken (30.1 MMBOE).

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As of December 31, 2011, less than 2% of our proved undeveloped reserves have been held as proved undeveloped for a period greater than five years, all of which are tertiary reserves. It is expected that the tertiary reserves will become proved developed reserves during the next several years as the remaining tertiary development at these fields is completed. It is expected that the remaining non-tertiary proved undeveloped reserves will be developed within the next five years.

	December 31,		
	2011	2010	2009
Estimated Proved Reserves			
Oil (MBbls)	357,733	338,276	192,879
Natural gas (MMcf)	625,208	357,893	87,975
Oil equivalent (MBOE)	461,934	397,925	207,542
Reserve Volumes Categories			
Proved developed producing:			
Oil (MBbls)	189,904	186,705	93,833
Natural gas (MMcf)	116,562	104,050	67,952
Oil equivalent (MBOE)	209,331	204,047	105,158
Proved developed non-producing:			
Oil (MBbls)	49,837	32,372	22,359
Natural gas (MMcf)	9,408	6,466	1,561
Oil equivalent (MBOE)	51,405	33,450	22,619
Proved undeveloped:			
Oil (MBbls)	117,992	119,199	76,687
Natural gas (MMcf)	499,238	247,377	18,462
Oil equivalent (MBOE)	201,198	160,428	79,765
Percentage of Total MBOE:			
Proved developed producing	45%	51%	51%
Proved developed non-producing	11%	9%	11%
Proved undeveloped	44%	40%	38%
Representative Oil and Natural Gas Prices:(1)			
Oil - NYMEX	$ 96.19	$ 79.43	$ 61.18
Natural gas - Henry Hub	$ 4.16	$ 4.40	$ 3.87
Present Values (thousands):(2)			
Discounted estimated future net cash flow before income taxes (PV-10 Value)(3)	$ 10,559,139	$ 7,292,344	$ 3,075,459
Standardized measure of discounted estimated future net cash flow after income taxes ("Standardized Measure")	$ 7,007,605	$ 4,917,927	$ 2,457,385

(1) The reference prices were based on the average first day of the month prices for each month during the respective year, adjusted for differentials by field to arrive at the appropriate net price Denbury receives. See Operating Results in Management’s Discussion and Analysis of Financial Condition and Results of Operations for details of oil and natural gas prices received, both including and excluding the impact of derivative settlements.

(2) 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.

(3) 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 (in thousands) was $3,551,534 at December 31, 2011, $2,374,417 at December 31, 2010, and $618,074 at December 31, 2009. 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 Note 15, Supplemental Oil and Natural Gas Disclosures (Unaudited), to the Consolidated Financial Statements for additional disclosures about the Standardized Measure.

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 Note 15, Supplemental Oil and Natural Gas Disclosures (Unaudited), to the Consolidated Financial Statements.

Item 1A. Risk Factors

Oil and natural gas prices are volatile. A substantial decrease in oil and natural gas prices could adversely affect our financial results.

Our future financial condition, results of operations, and cash flows, and the carrying value of our oil and natural gas properties, depend primarily upon the prices we receive for our oil and natural gas production. Oil and natural gas prices historically have been volatile and may continue to be volatile in the future, especially given current world geopolitical conditions. Oil and natural gas prices have continued their volatility, with NYMEX oil prices per Bbl increasing 8% between year-end 2010 and year-end 2011, and NYMEX natural gas prices per MMBtu decreasing by 32% during the year. Natural gas prices declined an additional 12% between December 31, 2011 and February 23, 2012. Future decreases in commodity prices could require us to record full cost ceiling test write-downs. The amount of any future write-down is difficult to predict and will depend upon oil and natural gas prices, the incremental proved reserves that might be added during each period and additional capital spent.

Our cash flow from operations is highly dependent on the prices that we receive for oil and natural gas. This price volatility also affects the amount of our cash flow available for capital expenditures and our ability to borrow money or raise additional capital. Oil prices are likely to affect us more than natural gas prices because oil comprised approximately 93% of our 2011 production and 77% of our December 31, 2011 proved reserves, with oil being an even larger percentage of our current production and future potential reserves and projects due to our focus on tertiary operations.

The prices for oil and natural gas are subject to a variety of additional 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;
- the domestic and foreign supply of oil and natural gas;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- domestic governmental regulations and taxes;
- the price and availability of alternative fuel sources;
- 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 in the Rocky Mountains that can delay or impede operations;
- market uncertainty;
- worldwide political events and conditions, including actions taken by foreign oil and 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. Also, prices for oil and prices for natural gas do not necessarily move in tandem. Declines in oil and natural gas prices would not only reduce revenue, but could reduce the amount of oil and natural gas that we can produce economically. If the oil and natural gas industry experiences significant price declines, we may, among other things, be unable to meet our financial obligations or make planned expenditures.

Over the past 13 years, oil prices have gone from near historic low prices around $12.00 per Bbl to record highs of approximately $145.00 per Bbl in July 2008. During the last half of 2008, oil prices declined precipitously, ending that year at a NYMEX price of $44.60 per Bbl. Oil prices then reversed course, generally increasing through 2010 and 2011, ending 2010 at a NYMEX price of $91.38 per Bbl and ending 2011 at a NYMEX price of $98.83 per Bbl. If this volatility repeats itself, oil prices could decline to a level that makes our tertiary or Bakken projects uneconomic. If that were to happen, we may decide to suspend future expansion projects, and if prices were to drop below the cash break-even point for an extended period of time, we may decide to shut-in existing production, either of which would have a material adverse effect on our operations. We have a practice of hedging approximately the next year and a half of production to mitigate the risks associated with price fluctuations (see Note 9, Derivative Instruments and Hedging Activities, to the Consolidated Financial Statements for details regarding our commodity derivative contracts). As of February 23, 2012, we have oil commodity derivative contracts in place covering approximately 54,000 Bbls/d during 2012 and 50,000 Bbls/d during the first three quarters of 2013. Since operating costs do not decrease as quickly as commodity prices, it is difficult to determine a precise break-even point for our tertiary projects. Based on prior history, we estimate our economic break-even (before corporate overhead, and based on expenses on these projects at current oil prices) occurs at per barrel dollar costs in the $40-per-barrel range, depending on the specific field and area.

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The prices we receive for our crude oil often do not correlate with NYMEX prices. The prices we receive for our crude oil production can vary from NYMEX oil prices depending on the quality of the crude oil we sell, the location of our crude oil production and the related markets we sell to, 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 a positive $25.00 per Bbl to a negative $30.00 per Bbl. On a corporate-wide basis, our NYMEX differentials over the last few years have ranged from approximately $9.00 per Bbl above NYMEX oil prices to over $5.00 per Bbl below NYMEX 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.

Natural gas price volatility has followed a different path during the last few years, with current prices depressed as a result of weak demand and significant natural gas storage in place, leading to excess gas supply. NYMEX natural gas prices averaged $4.16 per MMBtu during 2009, $4.40 per MMBtu during 2010, $4.03 per MMBtu during 2011, and ended 2011 at $2.99 per MMBtu. As of February 23, 2012, we have natural gas commodity derivative contracts in place covering approximately 20,000 MMBtu/d during 2012.

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

Our long-term growth strategy is focused on our CO2 tertiary recovery operations. The crude oil production from our tertiary recovery projects depends on having access to sufficient amounts of CO2. Our ability to produce this oil would be hindered if our supply of CO2 were limited due to problems with our current CO2 producing wells and facilities, including compression equipment, or catastrophic pipeline failure. Our anticipated future crude oil production is also dependent on our ability to increase the production volumes of CO2 and inject adequate amounts of CO2 into the proper formation and area within each oil field. The production of crude oil from tertiary operations is highly dependent on the timing, volumes and location of the CO2 injections. If our crude oil production were to decline, it could have a material adverse effect on our financial condition, results of operations and cash flows.

Our planned tertiary operations and the related construction of necessary CO2 pipelines could be delayed by difficulties in obtaining pipeline rights-of-way, other permits, or by the listing of certain species as threatened or endangered.

The production of crude oil from our planned tertiary operations is also dependent upon having access to pipelines to transport available CO2 to our oil fields at a cost that is economically viable. Our ongoing construction of CO2 pipelines will require us to obtain rights-of-way not only from private landowners, but in certain areas, from the federal government if the proposed pipelines cross federal lands. Certain states where we operate are considering the adoption of laws and regulations that would limit or eliminate a state’s ability 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 gas natural leases that have species, such as the sage grouse, that could be listed as threatened or endangered under the Endangered Species Act, which could lead to material restrictions as to federal land use. These sorts of laws, and regulations and court decisions, 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 our ability to secure rights-of-way or access land for current or future pipeline construction projects. As a result, obtaining rights-of-way may require additional regulatory and environmental compliance and additional expenditures, which could delay our CO2 pipeline construction schedule and initiation of operations of these pipelines, and/or increase the costs of constructing those pipelines.

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

If we are unable to generate sufficient cash flow 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. This default could permit the holders of such indebtedness to accelerate the maturity of such indebtedness and could cause defaults under other indebtedness, possibly resulting in our bankruptcy. Our ability to meet our obligations will depend 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.

As of February 23, 2012, we had outstanding $2.1 billion (principal amount) of subordinated notes at interest rates ranging from 6.0% to 9.75% at a weighted average interest rate of 8.33% and $470 million of bank debt secured by most of our properties. At February 23, 2012, we had $1.1 billion available on our bank credit facility. We currently have a bank borrowing base of $1.6 billion. The next regularly scheduled semiannual redetermination of the borrowing base for our bank credit facility will be in May 2012. Our bank borrowing base is adjusted at the banks' discretion and is based in part upon external factors, such as commodity prices, over which we have no control. If our then redetermined borrowing base is less than our outstanding borrowings under the facility, we will be required to repay the deficit over a period not to exceed four months.

We may incur additional indebtedness in the future under our bank credit facility in connection with our acquisition, development, exploitation and exploration of oil and natural gas producing properties. Further, 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 again decrease and remain at depressed levels for an extended period of time, our degree of leverage could increase substantially. The level of our indebtedness could have important consequences, including but not limited to the following:

- a substantial portion of our cash flows from operations may be dedicated to servicing our indebtedness and would not be available for capital expenditures or other purposes;

- our level of indebtedness may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions or general corporate and other purposes;

- our interest expense may increase in the event of increases in market interest rates, because bank borrowings are at variable rates of interest;

- our vulnerability to general adverse economic and industry conditions may be greater as a result of our level of indebtedness, and increases in interest rates thereon, potentially restricting us from making acquisitions, introducing new technologies or exploiting business opportunities;

- our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments may be limited by the covenants contained in the agreements governing our outstanding indebtedness limit; and

- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry. Our failure to comply with such covenants could result in an event of default under such debt instruments which, if not cured or waived, could have a material adverse effect on us.

Product price derivative contracts may expose us to potential financial loss.

To reduce our exposure to fluctuations in the prices of oil and natural gas, we currently, and may in the future, enter into derivative contracts in order to economically hedge a portion of our oil and natural gas production. Derivative contracts expose us to risk of financial loss in some circumstances, including when:

- production is less than expected;

- the counter-party to the derivative contract defaults on its contract obligations; or

- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

In addition, these derivative contracts may limit the benefit we would receive from increases in the prices for oil and natural gas. Information as to these activities is set forth under Market Risk Management in Management's Discussion and Analysis of Financial Condition and Results of Operations, and in Note 9, Derivative Instruments and Hedging Activities, to the Consolidated Financial Statements.

A worldwide financial downturn, such as the 2008 – 2009 financial crisis, or negative credit market conditions may have lasting effects on our liquidity, business and financial condition that we cannot predict.

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 the current sovereign debt crisis in Europe and related turmoil in the global financial system, could materially affect our liquidity, business and financial condition. These conditions have adversely impacted financial markets and have created substantial volatility and uncertainty, and may continue to do so, with the related negative impact on global economic activity and the financial markets. Negative credit market conditions could materially affect our liquidity and may inhibit our lenders from fully funding our bank credit facility or cause them to make the terms of our bank credit facility costlier and more restrictive. We are subject to semiannual reviews, as well as unscheduled reviews, of our borrowing base under our bank credit facility, and we do not know the results of future redeterminations or the effect of then-current oil and natural gas prices on that process. The economic situation could also adversely affect the collectability of our trade receivables or performance by our suppliers and cause our commodity hedging arrangements to be ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection. Additionally, negative economic conditions could lead to reduced demand for oil and natural gas, or lower prices for oil and natural gas, which could have a negative impact on our revenues.

Our future performance depends 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. 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, 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 four or five years prior to any resulting 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 meet expectations.

During the last few years, we have acquired several fields at a significant cost because we believe that they have significant additional potential through tertiary flooding and we paid a premium price for these properties based on that assumption. In addition, we plan to continue acquiring other oil fields that we believe are tertiary flood candidates. We are investing significant amounts of capital as part of this strategy. If we are unable to successfully develop the potential oil in these acquired fields, it would negatively affect the return on our investment on these acquisitions and could severely reduce our ability to obtain additional capital for the future, fund future acquisitions, and negatively affect our financial results to a significant degree.

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

Drilling activities are subject to many risks, including the risk that new wells drilled by us will not discover commercially productive reservoirs or 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 in the Rocky Mountain region that can delay or impede operations;
- compliance with environmental and other governmental requirements; and
- cost of, or shortages or delays in the availability of, drilling rigs, equipment, pipelines and services.

Our operations are subject to all the risks normally incident to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including encountering 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.

The nature of these risks is such that some liabilities could exceed our insurance policy limits, or, as in the case of environmental fines and penalties, 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 CO2 tertiary recovery projects require a significant amount of electricity to operate the facilities. If these costs were to increase significantly, it could have an adverse effect upon the profitability of these operations. Additionally, a portion of our production activities involve CO2 injections into fields with wells plugged and abandoned by prior operators. It is often difficult to determine whether a well has been properly plugged prior to commencing injections and pressuring the oil reservoirs. If wells have not been properly plugged, we will have to modify the wells, which can increase costs, delay our operations and reduce our production.

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 are conducted in areas subject to extreme weather conditions and often in difficult terrain. As a result, our operations may be delayed because of cold, snow and wet conditions. During a harsh winter, certain operations may only be practical during non-winter months. Unusually severe weather could delay certain of these operations, including the construction of CO_2 pipelines, the drilling of new wells and production from existing wells, and depending on the severity of the weather, could have a negative effect on our results of operations in this region. Further, certain of our operations are limited to certain time periods due to environmental regulations, which slow down our operations, cause delays and can have a negative effect on our results of operations.

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 to drill wells and conduct field operations, 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. During periods of high oil and natural gas prices, we have experienced shortages of equipment used in our tertiary facilities, drilling rigs and other equipment, as demand for rigs and equipment has increased along with higher commodity prices. Higher oil and natural gas prices generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, oilfield equipment and services, and personnel in our exploration and production operations. We have experienced such equipment shortages and price increases particularly in the Bakken play due to high demand for drilling rigs there. 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 those wells and conduct those operations that we currently have planned and budgeted, causing us to miss our forecasts and projections.

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

Hydraulic fracturing is a practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations and is used in the Bakken formations we acquired as part of the Encore Merger. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. The EPA, however, recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the federal Safe Drinking Water Act's ("SDWA") Underground Injection Control ("UIC") Program by posting a new requirement that requires facilities to obtain permits to use diesel fuel in hydraulic fracturing operations. (The U.S. Energy Policy Act of 2005, which exempts hydraulic fracturing from regulation under the SDWA, prohibits the use of diesel fuel in the fracturing process without a UIC permit.) Although the EPA has yet to take any action to enforce or implement this newly-asserted regulatory authority, industry groups have filed suit challenging the EPA's recent decisions. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with results of the study anticipated to be available by late 2012, and various committees have been investigating hydraulic fracturing practices. In addition, legislation was proposed in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In 2011, between 10% and 15% of our revenues were derived from operations related to hydraulic fracturing.

Although it is difficult to predict the ultimate outcome of these and future initiatives, these or any other new laws or regulations that significantly restrict hydraulic fracturing could make it more difficult or costly for us to drill and produce from conventional or tight formations, and fracturing activities could become subject to additional permitting and financial assurance requirements, increased monitoring, reporting and recordkeeping obligations, and also attendant permitting delays and potential increases in costs. At this time, it is not possible to estimate the potential impact on our business that may arise if federal or state legislation governing hydraulic fracturing is enacted into law.

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 proposed or are under consideration by the current federal administration, Congress and various federal agencies. Among these proposals are: (1) climate change/carbon tax legislation introduced in Congress and EPA greenhouse gas regulations, including decisions on the application of New Source Performance Standards (NSPS) for petroleum refineries due by November 2012; (2) proposals contained in the President's budget, along with legislation introduced in Congress, none of which have passed Congress, to impose new taxes on, or repeal various tax deductions available to, oil and gas producers, such as the current tax deduction for intangible drilling and development costs and the current deduction for qualified tertiary injectant expenses, which 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 being considered by Congress that would subject the process of hydraulic fracturing to federal regulation under the SDWA and new or anticipated Interior Department and EPA regulations 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

Transportation Department to prescribe minimum safety standards for CO2 pipelines, any of which could affect Company operations, their effectiveness and the costs thereof. Generally, any such future laws and regulations could result in increased costs or additional operating restrictions and could have an effect on demand for oil and natural gas or prices at which it can be sold. Until any such legislation or regulations are enacted or adopted, it is not possible to gauge their impact on our future operations or our results of operations and financial condition.

The loss of more than one of our large oil and natural gas purchasers could have a material adverse effect on our operations.

For the year ended December 31, 2011, two purchasers each accounted for more than 10% of our oil and natural gas revenues and in the aggregate, for 59% of these revenues. 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.

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 regulation. 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 or 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 reduction of the quantities and net present value of our reserves.

The reserve data included in documents incorporated by reference represent only estimates. Quantities of proved reserves are estimated based on economic conditions, including oil and natural gas prices in existence at the date of assessment. 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, operating results and cash flows. Actual future prices and costs may be materially higher or lower than the prices and cost as of the date of the estimate.

As of December 31, 2011, approximately 44% of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and may require successful drilling operations. The reserve data assumes that we can and will make these expenditures and conduct these operations successfully, but these assumptions may not be accurate, and this may not occur.

Substantial acquisitions or other transactions could require significant external capital and could change our risk and property profile.

To finance acquisitions, we may need to substantially alter or increase our capitalization through the use of our bank credit facility, the issuance of debt or equity securities, the sale of production payments, or by other means. Such changes in capitalization could significantly affect our risk profile. Additionally, significant acquisitions or other transactions can change the character of our operations and business. The character of the new properties may be substantially different in operating or geological characteristics or geographic location than our existing properties.

We may experience an impairment of our goodwill.

We test goodwill for impairment annually during the fourth quarter, or more frequently if an event occurs or circumstances change that may indicate the fair value of a reporting unit is less than the carrying amount. The need to test for impairment can be based on several indicators, such as a significant reduction in the price of oil or natural gas, a full cost ceiling write-down of oil and natural gas properties, or significant changes in the expected timing of production.

Fair value calculated for the purpose of testing for impairment of our goodwill is estimated using the expected present value of future cash flows method and comparative market prices when appropriate. A significant amount of judgment is involved in performing these fair value estimates for goodwill since the results are based on estimated future cash flows and assumptions related thereto. Significant assumptions include estimates of future oil and natural gas prices, projections of estimated quantities of oil and natural gas reserves, estimates of future rates of production, timing and amount of future development and operating costs, estimated availability and cost of CO_2, projected recovery factors of reserves and risk-adjusted discount rates. We base our fair value estimates on projected financial information that we believe to be reasonable; however, actual results may differ from those projections.

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.

To date we have not experienced any material losses relating to cyber-attacks, however there can be no assurance that we will not 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 protective measures or to investigate and remediate any cyber-vulnerabilities.

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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 Off-Balance Sheet Agreements – Commitments and Obligations in Management's Discussion and Analysis of Financial Condition and Results of Operations, 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 other 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 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 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 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.

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PART II

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 of February 10, 2012, 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 1,550. On February 24, 2012, the last reported sale price of Denbury's common stock, as reported on the NYSE, was $20.91 per share.

	2011		2010	
	High	Low	High	Low
First Quarter	$24.56	$18.45	$16.87	$13.55
Second Quarter	24.86	18.70	19.15	14.64
Third Quarter	20.85	11.50	17.02	14.18
Fourth Quarter	17.45	10.86	19.79	16.24

We have never paid any dividends on our common stock, and we currently do not anticipate paying dividends in the foreseeable future. Also, our bank credit facility limits the amount of dividends we can pay on our common stock to $500 million, subject to other restrictions. No unregistered securities were sold by the Company during 2011.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Month	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 2011	11,017,712	$13.59	10,990,939	-
November 2011	1,105,440	14.79	1,092,501	-
December 2011	2,036,070	14.76	2,029,170	-
Total	14,159,222	13.85	14,112,610	-

Between early October 2011, when we announced the commencement of a common share repurchase program for up to $500 million of Denbury common stock, and December 31, 2011, we have repurchased 14,112,610 shares of Denbury common stock (approximately 3.5% of our outstanding shares of common stock at September 30, 2011) for $195.2 million, or $13.83 per share. The program has no pre-established ending date, and may be suspended or discontinued at any time. The Company is not obligated to repurchase any dollar amount or specific number of shares of its common stock under the program.

All other stock purchases during the fourth quarter of 2011 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.

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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, 2011, 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) from December 31, 2006 to December 31, 2011.
[Missing Graphic Reference]

	December 31,					
	2006	2007	2008	2009	2010	2011
Denbury Resources Inc.	$100.00	$214.11	$78.59	$106.51	$137.39	$108.67
S&P 500 (1)	100.00	105.49	66.46	84.05	96.71	98.75
Dow Jones US Exploration & Production (2)	100.00	143.67	86.02	120.92	141.16	135.25

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Item 6. Selected Financial Data

In thousands, except per share data or otherwise noted	Year Ended December 31, 2011	2010 (1)	2009	2008	2007
Consolidated Statements of Operations Data:					
Revenues and other income:					
Oil, natural gas, and related product sales	$ 2,269,151	$ 1,793,292	$ 866,709	$ 1,347,010	$ 952,788
Other	40,173	128,499	22,441	24,046	20,272
Total revenues and other income	$ 2,309,324	$ 1,921,791	$ 889,150	$ 1,371,056	$ 973,060
Net income (loss) attributable to Denbury stockholders(2)	573,333	271,723	(75,156)	388,396	253,147
Net income (loss) per common share:					
Basic	1.45	0.73	(0.30)	1.59	1.05
Diluted	1.43	0.72	(0.30)	1.54	1.00
Weighted average number of common shares outstanding:					
Basic	396,023	370,876	246,917	243,935	240,065
Diluted	400,958	376,255	246,917	252,530	252,101
Consolidated Statements of Cash Flow Data:					
Cash provided by (used by):					
Operating activities	$ 1,204,814	$ 855,811	$ 530,599	$ 774,519	$ 570,214
Investing activities(3)	(1,605,958)	(354,780)	(969,714)	(994,659)	(762,513)
Financing activities(4)	37,968	(139,753)	442,637	177,102	198,533
Production (average daily):					
Oil (Bbls)	60,736	59,918	36,951	31,436	27,925
Natural gas (Mcf)	29,542	78,057	68,086	89,442	97,141
BOE (6:1)	65,660	72,927	48,299	46,343	44,115
Unit Sales Price (excluding impact of derivative settlements):					
Oil (per Bbl)	$ 100.03	$ 75.97	$ 57.75	$ 92.73	$ 69.80
Natural gas (per Mcf)	4.79	4.63	3.54	8.56	6.81
Unit Sales Price (including impact of derivative settlements):					
Oil (per Bbl)	$ 98.90	$ 71.69	$ 68.63	$ 90.04	$ 68.84
Natural gas (per Mcf)	7.34	6.45	3.54	7.74	7.66
Costs per BOE:					
	$ 21.17	$ 17.67	$ 17.85	$ 17.71	$ 13.98

Lease operating expenses					
Taxes other than income	6.16	4.53	2.45	3.06	2.60
General and administrative	5.24	5.04	5.77	3.36	2.86
Depletion, depreciation and amortization	17.07	16.32	13.52	13.08	12.17
Proved Oil and Natural Gas Reserves:					
Oil (MBbls)	357,733	338,276	192,879	179,126	134,978
Natural gas (MMcf)(5)	625,208	357,893	87,975	427,955	358,608
MBOE (6:1)	461,934	397,925	207,542	250,452	194,746
Proved Carbon Dioxide Reserves:					
Gulf Coast region (MMcf)(6)	6,685,412	7,085,131	6,302,836	5,612,167	5,641,054
Rocky Mountain region (MMcf)(7)	2,195,534	2,189,756	-	-	-
Proved Helium Reserves Associated with Denbury's Production Rights:(8)					
Rocky Mountain region (MMcf)	12,004	7,159	-	-	-
Consolidated Balance Sheet Data:					
Total assets	$ 10,184,424	$ 9,065,063	$ 4,269,978	$ 3,589,674	$ 2,771,077
Total long-term liabilities	4,716,659	4,105,011	1,903,951	1,363,539	1,102,066
Stockholders' equity(9)	4,806,498	4,380,707	1,972,237	1,840,068	1,404,378

(1) On March 9, 2010, we acquired Encore Acquisition Company ("Encore"). We consolidated Encore's results of operations beginning March 9, 2010. See Note 2, Acquisitions and Divestitures, to the Consolidated Financial Statements for further discussion of this transaction.

(2) During 2010, we consolidated Encore's results of operations beginning March 9, 2010. In 2009, we had a pretax charge of $236.2 million associated with our commodity derivative contracts. In 2008, we had a full cost ceiling test write-down of $226 million ($140.1 million net of tax) and pretax expense of $30.6 million associated with a cancelled acquisition. These charges were partially offset by pretax income of $200.1 million on our commodity derivative contracts.

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(3) During 2011, we closed our purchase of a 57.5% working interest in Riley Ridge that we did not already own for $214.8 million after closing adjustments. During 2010, we closed our purchase of Encore, a cash and stock transaction that included a cash outlay of $815.0 million, net of cash acquired; closed the purchase of a 42.5% working interest in Riley Ridge for $132.3 million; and sold non-strategic Encore assets for aggregate cash proceeds of $1.5 billion. During February 2009, we closed our $201 million purchase of Hastings Field, and in December 2009, we closed our $430.7 million purchase of Conroe Field (for $269.8 million in cash and the issuance of 11,620,000 shares of common stock). We sold our Barnett Shale natural gas assets in 2009 for aggregate proceeds of $469.7 million.

(4) In February 2011, we issued $400 million of 6 % Senior Subordinated Notes due 2021 and between February and April 2011, we repurchased approximately $225 million in principal amount of 7½% Senior Subordinated Notes due 2013 and $300 million in principal amount of 7½% Senior Subordinated Note due 2015. In February 2010, we issued $1.0 billion of 8¼% Senior Subordinated Notes due 2020 and in March and April 2010, we repurchased approximately $500.5 million and $95.7 million, respectively, in principal amount of senior subordinated notes previously issued by Encore (see Note 5, Long-term Debt, to the Consolidated Financial Statements). In February 2009, we issued $420 million of 9¾% Senior Subordinated Notes due 2016.

(5) During 2009, we sold our Barnett Shale assets.

(6) 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 Denbury's net revenue interest was approximately 5.3 Tcf, 5.6 Tcf and 5.0 Tcf at December 31, 2011, 2010 and 2009, respectively, and include reserves dedicated to volumetric production payments of 84.7 Bcf at December 31, 2011, 100.2 Bcf at December 31, 2010, 127.1 Bcf at December 31, 2009, 153.8 Bcf at December 31, 2008, and 182.3 Bcf at December 31, 2007. (See Note 16, Supplemental CO_2 and Helium Disclosures (Unaudited), to the Consolidated Financial Statements.)

(7) Proved CO_2 reserves in the Rocky Mountain region consist of our reserves at Riley Ridge and are presented on a gross or 8/8ths working interest basis, of which Denbury's net revenue interest was 1.6 Tcf and 0.9 Tcf at December 31, 2011 and 2010, respectively.

(8) Reserves associated with helium production rights include helium reserves located in the acreage in the Rocky Mountain region for which we have the right to extract the helium. The U.S. government retains title to the helium reserves and we retain the right to extract and sell the helium on behalf of the government in exchange for a fee. The helium reserves are presented net of the fee we will remit to the U.S. government.

(9) We have never paid any dividends on our common stock.

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 Data. 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 report, 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 than our forward-looking statements.

Overview

We are a growing independent oil and natural gas company. We are the largest combined oil and natural gas producer in both Mississippi and Montana, own the largest CO2 reserves used for tertiary oil recovery east of the Mississippi River, and hold significant operating acreage in the Rocky Mountain and Gulf Coast regions. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis on our CO2 tertiary recovery operations.

We completed the acquisition of Encore on March 9, 2010 (the "Encore Merger"), and during the remainder of 2010 executed on our plan to divest non-strategic Encore properties. The magnitude of the Encore acquisition and subsequent 2010 asset divestitures impacts the comparability of our 2010 and 2011 financial results in many ways, including oil and natural gas production, revenues and operating expenses. Our financial results for the year ended December 31, 2010 include the results of operations of Encore from the date of the acquisition through December 31, 2010, and were further impacted by our divestitures of non-strategic Encore properties and our ownership interests in Encore Energy Partners ("ENP") between May 2010 and December 31, 2010.

2011 Operating Highlights. We achieved record net income and cash flows from operations in 2011. We had net income of $573.3 million, or $1.45 per basic common share, during 2011, compared to net income of $271.7 million, or $0.73 per basic common share, during 2010. The increase between the two periods is primarily attributable to a $475.9 million increase in oil and natural gas revenues due to higher oil prices, partially offset by lower production as a result of assets sold in late 2010, and to a lesser extent due to an $87.9 million decrease in costs related to the Encore Merger. These increases to net income between 2010 and 2011 were offset by the absence in 2011 of a $101.5 million gain on the 2010 sale of Genesis Energy, LLC, and to a lesser extent were due to a $16.1 million loss on the early extinguishment of debt in 2011, certain asset impairment charges in 2011 related to our investment in Vanguard common units ($6.3 million), and the abandonment of our investment in certain CO2 properties ($16.6 million). Overall, our total expenses decreased by $57.4 million, from $1.44 billion in 2010 to $1.39 billion in 2011. Our cash flow from operations was $1.2 billion in 2011, compared to $855.8 million in 2010, the increase also primarily due to the increase in oil revenues.

During 2011, our oil and natural gas production, which was 93% oil, averaged 65,660 BOE/d, compared to 72,927 BOE/d produced during 2010. The decrease in production is primarily attributable to the 2010 sales of non-strategic legacy Encore assets and our ownership interests in ENP. See Results of Operations — Operating Results — Production for more information.

Oil prices during 2011 were considerably higher than prices during 2010, with NYMEX oil prices averaging $95.08 per Bbl in 2011, compared to average NYMEX prices of $79.51 per Bbl in 2010. Oil revenues made up approximately 98% of our oil and natural gas revenues in 2011 as compared to approximately 93% in 2010. Our average price per barrel of oil, excluding the impact of derivative contracts, was $100.03 per barrel in 2011, as compared to $75.97 per barrel in 2010, a 32% increase between the two periods. Oil prices received in 2011 were positively impacted by the favorable price differential for crude oil sold under Louisiana Light Sweet ("LLS") pricing. See Results of Operations – Operating Results – Oil and Natural Gas Revenues below for more information.

August 2011 Acquisition of Remaining Working Interest in Riley Ridge. On August 1, 2011, we acquired the remaining 57.5% working interest that we did not already own in the Riley Ridge Federal Unit ("Riley Ridge"), the remaining 57.5% interest in the associated Riley Ridge gas plant, along with interests in certain surrounding acreage. The purchase price after closing adjustments was $214.8 million. Riley Ridge not only contains significant natural gas and helium, but is strategic to our tertiary oil field development in the Rocky Mountain region as it provides a significant long-term source of CO2 that we plan to use in our tertiary floods. We currently expect the gas plant to be operational with the first production of natural gas and helium during the second quarter of 2012. The CO2 will be re-injected into the reservoir until we have completed an additional separation facility and a CO2 pipeline to the field, which is expected to be completed in 2016.

As of December 31, 2011, Riley Ridge and minor surrounding acreage contained net proved reserves of 415 Bcf of natural gas and 2.2 Tcf of CO2 reserves. The CO2 reserve estimates are based on the gross working interest of the CO2 reserves, of which Denbury's net revenue interest is approximately 1.6 Tcf. The helium reserves at Riley Ridge are owned by the U.S. government; however, we have the rights to produce and sell the helium reserves on behalf of the government in exchange for a fee. As of December 31, 2011, we estimate that Riley Ridge contains proved helium reserves of 12.0 Bcf, net of fees to be remitted to the U.S. government.

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Addition of Proved Oil and Natural Gas Reserves. We added 88.0 MMBOE of estimated proved reserves during 2011, including 48.2 MMBOE from the development of Bakken properties, 237 Bcf (39.5 MMBOE) of natural gas reserves from the Riley Ridge acquisition completed in August 2011, which is discussed above, and minor revisions to other properties.

Recent Common Share Repurchase Program. In October 2011, we commenced a common share repurchase program approved by our Board of Directors for up to $500 million of Denbury common shares. Between early October 2011 and December 31, 2011, we repurchased 14,112,610 shares of Denbury common stock (approximately 3.5% of our outstanding shares of common stock at September 30, 2011) for $195.2 million, or $13.83 per share. The program has no pre-established ending date and may be suspended or discontinued at any time. The Company is not obligated to repurchase any dollar amount or specific number of shares of its common stock under the program.

Pending 2012 Non-Core Gulf Coast Assets Divestiture. In January 2012, we entered into a definitive agreement to sell certain non-core assets primarily located in central and southern Mississippi and in southern Louisiana for $155 million, subject to customary closing adjustments. The sale is subject to customary closing conditions and is expected to close by late February 2012, with an effective date of December 1, 2011. Production associated with the properties to be sold averaged 1,805 BOE/d during 2011. See Note 14, Subsequent Events, to the Consolidated Financial Statements.

Capital Resources and Liquidity

We currently estimate our 2012 capital spending will be approximately $1.35 billion, net of estimated equipment leases ($75 million) and excluding capitalized interest and start-up costs associated with new tertiary floods. Our current 2012 capital budget includes the following:

- $365 million allocated for tertiary oil field expenditures,
- $400 million for development of our Bakken properties,
- $325 million for pipeline construction,
- $150 million to be spent on CO_2 sources, and
- $110 million to be spent in all other areas.

When we originally set our capital budget in late 2011, based on oil and natural gas commodity futures prices at that time and our 2012 production forecasts, we estimated that our capital budget (including capitalized interest and tertiary start-up costs) could be around $200 million greater than our 2012 anticipated cash flow from operations. Recent increases in oil prices, if they remain, will likely increase our anticipated cash flow from operations and significantly reduce the amount by which we expected to outspend cash flow. In light of this, we are considering an increase in our 2012 capital budget. We plan to fund any shortfall between our cash flow from operations and our capital spending with asset divestitures ranging from $150 million to $300 million in the aggregate or, if necessary, borrowings under our bank credit facility. In January 2012, we received net proceeds of $83.5 million from the sale of our Vanguard common units, and we anticipate receiving proceeds of approximately $155 million from the sale of non-core Gulf Coast assets in late February 2012 (see Pending 2012 Non-Core Gulf Coast Assets Divestiture above). We are also marketing one other non-core property that we expect to sell later in 2012. Based on our transactions in early 2012, we expect that we will achieve our targeted cash inflows from asset divestitures.

As discussed above, in October 2011 we commenced a common share repurchase program for up to $500 million of Denbury shares. Our goal for 2012 is to limit any incremental debt incurred for such repurchases and for our 2012 capital budget to $250 million or less, and we estimate cumulative share repurchases of up to $250 million in determining our 2012 capital budget. Of the $250 million in projected repurchases, thus far we have repurchased $195.2 million. Based on our current anticipated levels of cash flows from operations and proceeds from asset sales, we currently expect to stay within our stated goal for incremental debt related to our share repurchase program and 2012 capital budget. Our share repurchases will be determined based on various parameters; therefore, our share repurchases may be less or more than our estimated $250 million.

During 2011, we extended the maturity of our bank credit facility from March 2014 to May 2016. As part of our semiannual bank review, on September 1, 2011, our borrowing base for our bank credit facility was reaffirmed at $1.6 billion. Our next borrowing base redetermination is scheduled for May 1, 2012; we currently do not anticipate any reduction in our borrowing base as part of that redetermination, as we believe that we have more than enough collateral for the current borrowing base, based on current commodity prices and our proved asset base. As of February 23, 2012, we had $470 million of bank debt outstanding on our $1.6 billion bank credit facility and estimated cash of $195 million, leaving us significant liquidity to fund any cash shortfall for capital expenditures.

To help protect our cash flows in case commodity prices were to decrease significantly from the levels of futures strip prices near the end of February 2012, we currently have oil and natural gas derivative commodity contracts in place through the third quarter of 2013. Our oil derivative commodity contracts cover approximately 85–90% of our anticipated proved oil production in 2012 and 75–80% in the first three quarters of 2013. Over 90% of our continuing production (excluding production from properties sold) is oil, and most of our oil contracts are costless collars with NYMEX floor prices between $70 and $80 per Bbl. See Note 9, Derivative Instruments and Hedging Activities to the Consolidated Financial Statements for further details regarding the prices and volumes of our commodity derivative contracts.

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We continually monitor our capital spending and anticipated cash flows and believe that we can adjust our capital spending up or down depending on cash flows; however, any such reduction in capital spending could reduce our anticipated production levels in future years. For 2012 and some future years, we have contracted for certain capital expenditures; therefore, we cannot eliminate all of our capital commitments without penalties. (See Off-Balance Sheet Arrangements – Commitments and Obligations for further information regarding these commitments.)

In February 2011, we issued, at par, $400 million of 6 % Senior Subordinated Notes due 2021. The net proceeds, together with cash on hand, were used to partially fund the repurchase of $525 million in principal amount of our outstanding 7½% Senior Subordinated Notes due 2013 and 7½% Senior Subordinated Notes due 2015. During 2011, we recognized $16.1 million of loss associated with the debt repurchases included in our Consolidated Statements of Operations under the caption "Loss on early extinguishment of debt." See Note 5, Long-Term Debt, to the Consolidated Financial Statements for more information related to the debt issuance and related tender offers.

Capital Expenditure Summary. The following table summarizes our capital expenditures by project area. Amounts include capitalized tertiary start-up costs and accrued capital expenditures:

	Year Ended December 31,		
In thousands	2011	2010	2009
Capital expenditures by project:			
Tertiary oil fields	$ 522,007	$ 371,274	$ 229,532
Bakken	435,159	108,363	-
CO2 pipelines	134,377	171,511	514,035
CO2 properties	103,541	73,316	61,921
Other areas	244,055	156,076	59,615
Capital expenditures before acquisitions and capitalized interest	1,439,139	880,540	865,103
Less: recoveries from sale/leaseback transactions	(70,332)	(40,490)	(49,313)
Net capital expenditures excluding acquisitions and capitalized interest	1,368,807	840,050	815,790
Acquisitions:			
Oil and natural gas property acquisitions	35,305	25,672	621,517
Consideration for Encore Merger(1)	-	2,952,515	-
Consideration for Riley Ridge acquisitions	214,779	132,257	-
Capitalized interest	61,586	66,815	68,596
Capital expenditures, net of sale/leaseback transactions	$ 1,680,477	$ 4,017,309	$ 1,505,903

(1) Consideration given in Encore Merger includes $2.09 billion for the fair value of Denbury common stock issued.

Our 2011 capital expenditures, excluding the Riley Ridge acquisition, were funded with $1.2 billion of cash flow from operations and cash on hand at the beginning of the period. The Riley Ridge acquisition was funded with incremental bank debt. Our 2010 capital expenditures, excluding the Encore acquisition, were funded with $855.8 million of cash flow from operations and incremental cash generated from the sale of non-strategic assets. Net cash used to acquire Encore was approximately $815 million, which was funded with incremental debt drawn under our bank credit facility as discussed in Note 2, Acquisitions and Divestitures, to the Consolidated Financial Statements.

Our 2009 capital expenditures were funded with $530.6 million of cash flow from operations, $516.8 million in net proceeds from the sale of oil and natural gas properties, $381.4 million in net proceeds from the February 2009 issuance of senior subordinated debt, $168.7 million from the issuance of 11,620,000 shares of our common stock as partial consideration for the acquisition of Conroe Field and $50.0 million in net bank borrowings.

Off-Balance Sheet Arrangements – Commitments and Obligations. At December 31, 2011, our largest contractual payment obligation that is not on our balance sheet relates to our operating leases, which primarily relate to the lease financing of certain equipment for CO_2 recycling facilities at our tertiary oil fields. Remaining lease payments for these operating leases totaled $247.2 million at year-end 2011. We also have several leases relating to office space and other minor equipment leases. At December 31, 2011, we had a total of $16.5 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. 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 and asset retirement obligations. For a further discussion of our future development costs, see the contractual obligations table below.

Under the Hastings Field acquisition agreement, we are committed to inject an average of at least 50 MMcf/d of CO2 (total of purchased and recycled) in the West Hastings Unit for the 90-day period prior to January 1, 2013. CO2 injections commenced in December 2010, and we are currently injecting volumes in excess of 50 MMcf/d. Additionally, we are required to make aggregate cumulative capital expenditures in this field through December 31, 2014, which are included in “Other obligations” in the table below. For a complete description of these arrangements, including penalties for failure to meet these contractual commitments, see Note 11, Commitments and Contingencies, to the Consolidated Financial Statements.

CO2 Purchase Commitments. We have entered into long-term contracts to purchase man-made CO2 from eleven proposed plants or sources that will emit large volumes of CO2, six of which are in the Gulf Coast region, four in the Midwest (Illinois, Indiana and Kentucky), and one in the Rocky Mountain region. Two of the eleven projects are currently under construction, while construction of the remaining plants is either pending financing from federal grants or loan guarantees, or has been delayed due to economic or other reasons.

We anticipate the two projects that are currently under construction, together with our long-term purchase commitment to purchase CO2 from two existing facilities in Wyoming, ExxonMobil’s LaBarge facility and Lost Cabin, will provide us with approximately 200 MMcf/d to 375 MMcf/d of CO2. We expect to begin taking CO2 from ExxonMobil’s LaBarge facility during the second half of 2012, the Lost Cabin Gas Plant in late 2012 or early 2013, and the two plants currently under construction in 2013 or 2014. Anticipated payments for these long-term commitments are included in “Other obligations” in the contractual commitments table below.

The remaining contracts for man-made CO2 have been excluded from the contractual commitments table since they are cancelable, and construction has not yet begun on any of these plants. While various pre-construction steps for certain of the plants continue, there is some doubt as to whether they will be constructed at all. While it is likely that not every plant currently under contract will be constructed, there are other plants we have under consideration from time to time that could provide CO2 to us that would either supplement or replace some of the CO2 volumes from the proposed plants for which we currently have CO2 output purchase contracts, and we have had ongoing discussions with several of these other potential sources. If all nine of the remaining plants were constructed, these combined CO2 sources would provide us with estimated aggregate CO2 volumes of 1.4 Bcf/d to 2.3 Bcf/d, although we estimate the earliest that this source of man-made CO2 would become available to us is 2014. The base price of CO2 per Mcf from these CO2 sources varies by plant and location, but is generally higher than our most recent “all-in” cost of CO2 from Jackson Dome using current oil prices. Prices for CO2 delivered from these projects are expected to be competitive with the cost of our natural CO2 after adjusting for our share of potential carbon emissions reduction credits using estimated futures prices of carbon emissions reduction credits. If all nine of the remaining plants are constructed, the aggregate purchase obligation for this CO2 is currently estimated to be approximately $215 to $390 million per year, assuming a $100 per Bbl NYMEX oil price, before any potential savings from our share of carbon emissions reduction credits. All of the contracts have price adjustments that fluctuate based on the price of oil.

A summary of our obligations at December 31, 2011, is presented in the following table:

	Payments Due by Period						
In thousands	2012	2013	2014	2015	2016	Thereafter	Total
Contractual Obligations:							
Bank Credit Agreement(1)	$ -	$ -	$ -	$ -	$ 385,000	$ -	$ 385,000
Estimated interest payments on Bank Credit Agreement and subordinated debt(1)	178,704	178,704	178,656	178,623	124,954	375,023	1,214,664
Subordinated debt(1)	-	-	1,072	485	651,270	1,398,523	2,051,350
Pipeline lease obligations(2)	30,689	32,469	34,036	31,847	30,912	344,233	504,186
Operating lease obligations	36,207	37,509	34,369	33,536	31,349	74,269	247,239
Capital lease obligations	2,206	1,447	664	106	106	510	5,039
Other obligations(3)	284,898	119,380	136,569	93,148	93,034	1,039,298	1,766,327
Derivative contracts payment(4)	26,523	18,872	-	-	-	-	45,395
Other Cash Commitments:							
Future development costs on proved oil and gas reserves, net of other obligations(5)	496,666	665,879	527,201	579,962	309,247	92,811	2,671,766
Future development cost on proved CO2 reserves, net of other obligations(6)	7,020	13,000	11,000	20,000	-	76,000	127,020
Asset retirement obligations(7)	4,876	1,342	517	4,766	12,361	254,621	278,483
Total	$ 1,067,789	$ 1,068,602	$ 924,084	$ 942,473	$ 1,638,233	$ 3,655,288	$ 9,296,469

(1) These long-term borrowings and related interest payments are further discussed in Note 5, Long-Term Debt, to the Consolidated Financial Statements. This table assumes that our long-term debt is held until maturity.

(2) Represents estimated future cash payments under a long-term transportation service agreement for the Free State Pipeline and future minimum cash payments in a 20-year financing lease for the NEJD pipeline system. Both transactions were entered into during 2008 and are being accounted for as financing leases. The payment required for the Free State Pipeline is variable based upon the amount of the CO2 we ship through the pipeline, and the commitment amounts disclosed above for that financing lease are computed based upon our internal forecasts. Approximately $261 million of these payments, in the aggregate, represent interest. See Note 5, Long-Term Debt, to the Consolidated Financial Statements.

(3) Represents future cash commitments under contracts in place as of December 31, 2011, primarily for pipe, pipeline construction contracts, anthropogenic CO2 contracts, 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, which for 2012 is currently set at $1.35 billion, exclusive of acquisitions. In certain cases we have the ability to terminate contracts for equipment, in which case we would be liable only for the cost incurred by the vendor up to that point; however, as we currently do not anticipate cancelling those contracts, these amounts include our estimated payments under those contracts. 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 cancelled with regard to any specific vendor, even though the expense itself may be required for ongoing normal operations of the Company.

(4) Represents the fair value of our derivative liabilities as of December 31, 2011. The ultimate settlement amounts of our derivative obligations are unknown because they are subject to continuing market risk. See further discussion of our derivative contracts and their market price sensitivities in Market Risk Management below in this Management's Discussion and Analysis of Financial Condition and Results of Operations, and in Note 9, Derivative Instruments and Hedging Activities, to the Consolidated Financial Statements.

(5) Represents projected capital costs as scheduled in our December 31, 2011, proved reserve report that are necessary in order to recover our proved oil and natural gas reserves. These are not contractual commitments and are net of any other capital obligations shown under "Contractual Obligations" in the table above.

(6) Represents projected capital costs that are necessary in order to recover our proved CO2 reserves from our CO2 source wells used to produce CO2 for our tertiary operations. These are not contractual commitments and are net of any other capital obligations shown above.

(7) Represents the estimated future asset retirement obligations on an undiscounted basis. The present discounted asset retirement obligation is $93.5 million, as determined under the Asset Retirement and Environmental Obligations topic of the FASC, and is further discussed in Note 3, Asset Retirement Obligations, to the Consolidated Financial Statements.

We have long-term contracts that require us to deliver CO_2 to industrial CO_2 customers at various contracted prices, plus we have a CO_2 delivery obligation pursuant to three 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 327 Bcf of CO_2 to these customers over the next 14 years; however, since the group as a whole has historically taken less CO_2 than the maximum allowed in their contracts, based on the current level of deliveries, we project that our commitment would likely be reduced to approximately 240 Bcf. The maximum volume required in any given year is approximately 109 MMcf/d. Given the size of our Jackson Dome proved CO_2 reserves at December 31, 2011 (approximately 6.7 Tcf before deducting approximately 84.7 Bcf for the three VPPs), our current production capabilities and our projected levels of CO_2 usage for our own tertiary flooding program, we believe that we will be able to meet these delivery obligations.

In conjunction with the August 1, 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. Subsequently, we amended this contract to provide for annual delivery (to the 8/8ths working interest) of 127 MMcf of helium (previously 200 MMcf) during the first two years of the contract and thereafter to provide for delivery of 400 MMcf of helium per year. If the contracted quantity of helium is not supplied, we are obligated to compensate the third-party helium purchaser for the amount of the shortfall in an amount not to exceed $8.0 million per year. The start-up of the Riley Ridge plant is currently expected to occur in the second quarter of 2012.

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CO2 Operations

Overview. As discussed in Item 1, Business and Properties – Oil and Natural Gas Operations – Enhanced Oil Recovery Overview above, our tertiary operations have grown to the point that approximately 32% of our December 31, 2011, proved oil and natural gas reserves are proved tertiary oil reserves, almost 47% of our forecasted 2012 oil and natural gas production is expected to come from tertiary oil operations (on a BOE basis), and approximately 62% of our 2012 planned capital expenditures are related to our tertiary operations. We particularly like this play as (1) it has a lower risk, as we are working with oil fields that have significant historical production and data, (2) it provides a reasonable rate of return at relatively low oil prices (we estimate that our economic break-even point on a per-barrel basis before corporate-related overhead and expenses on these projects at current oil prices is in the $40 per barrel range, depending on the specific field and area), and (3) we have limited competition for this type of activity in our geographic regions.

Our Gulf Coast region is well developed, as we have been conducting tertiary recovery in this area for over 12 years. In the Gulf Coast region, we own, or control through long-term financing leases, an extensive network of CO2 pipelines and own the only significant natural resource of CO2 in the area known to us, and these large volumes of CO2 drive the play. Since we are just beginning our tertiary operations in the Rocky Mountain region, we have significantly fewer oil fields, and our CO2 sources and CO2 pipelines in this region are in the development stage. See further discussion regarding our tertiary operations in Item 1, Business and Properties – Oil and Natural Gas Operations – Rocky Mountain Region – Future Rocky Mountain Tertiary Properties without Proved Tertiary Reserves or Tertiary Production at December 31, 2011.

CO2 Resources. Since we acquired the Jackson Dome CO2 source located near Jackson, Mississippi in 2001, we have continued to develop the area and have increased the proven CO2 reserves from approximately 800 Bcf at the time of the acquisition to approximately 6.7 Tcf as of December 31, 2011. During 2011, we drilled three CO2 wells and started the drilling of an exploration CO2 well on a new structure identified by our seismic program. See Item 1, Business and Properties – Oil and Natural Gas Operations – Enhanced Oil Recovery Overview. Our CO2 reserves at Jackson Dome were essentially the same at both year-end 2011 and 2010, after consideration of 368.4 Bcf of CO2 produced during the year. The estimate of 6.7 Tcf of proved Gulf Coast CO2 reserves is based on a gross working interest of the CO2 reserves, of which our net revenue interest is approximately 5.3 Tcf. Both reserve estimates are included in the evaluation of proven CO2 reserves prepared by DeGolyer and MacNaughton. In discussing the available CO2 reserves, we disclose the gross amount of proved reserves, as this is the amount that is available for our tertiary recovery programs, industrial users and VPPs, as we are responsible for distributing the entire CO2 production stream for all of the owners of the gross reserves. We currently estimate that it will take approximately 1.9 Tcf of CO2 to develop and produce the proved tertiary oil recovery reserves we have recorded at December 31, 2011, in Phases 1 – 5.

Our average daily CO2 production during 2011, 2010 and 2009 was approximately 1.0 Bcf/d, 852 MMcf/d and 683 MMcf/d, respectively. As of February 23, 2012, we currently estimate that we are capable of producing and transporting approximately 1.1 Bcf/d of CO2, approximately 10 times the rate that we were capable of producing at the time of our initial acquisition in 2001. We continue to drill additional CO2 wells, with four more wells planned for 2012 in order to further increase our proved CO2 reserves and production capacity. Our drilling activity at Jackson Dome will continue beyond 2012, as our current forecasts for the existing nine phases suggest that we will need additional volumes of CO2.

Our cost to produce and pay royalties and taxes for the CO_2 we utilize in our tertiary floods was approximately $0.26 per Mcf in 2011, as compared to our 2010 average cost of $0.22 per Mcf and 2009 average cost of $0.17 per Mcf. The changes in our cost of CO_2 are primarily directly attributable to changes in oil prices, as the royalty we pay is directly tied to oil prices. Our estimated cost per thousand cubic feet of CO_2 during 2011 was approximately $0.31 per Mcf, after inclusion of depreciation and amortization expense related to the CO_2 production but excluding depreciation of our CO_2 pipelines, as compared to approximately $0.30 per Mcf during 2010 and $0.25 per Mcf during 2009.

Overview of Tertiary Economics. When we began our Gulf Coast tertiary operations several years ago, our operations were generally economic at oil prices below $20 per Bbl, although the economics varied by field. Our costs have escalated during the last several years due to general cost inflation in the industry and higher oil prices, and we estimate that our current break-even point for our Gulf Coast operations, before corporate overhead and interest, is at oil prices in the $40 per barrel range. Our inception-to-date Finding and Development Costs (including future development and abandonment costs but excluding CO_2 pipeline infrastructure capital expenditures and expenditures on fields without proven reserves) for our Gulf Coast tertiary oil fields through December 31, 2011, are approximately $14.60 per Bbl. See the definition of Finding and Development Costs in the Glossary and Selected Abbreviations. Currently, we forecast that Finding and Development Costs will average less than $10 per Bbl over the life of each field, excluding pipeline infrastructure, and less than $15 per Bbl over the life of each field, including pipeline infrastructure, depending on the state of a particular field at the time we begin operations, the amount of potential oil, the proximity to a pipeline or other facilities, and other factors. Our Finding and Development Costs to date do not include unproved potential reserves in fields with current proved reserves, and the calculations are based on estimates relating to reserves and costs for which there are inherent uncertainties. Our operating costs for our Gulf Coast tertiary operations are highly dependent on commodity prices; in general, we estimate they could range from approximately $22 per Bbl to $27 per Bbl over the life of each field, again depending on the field itself.

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Although we have yet to commence tertiary operations in our Rocky Mountain region, we expect that our tertiary operating costs, including the cost of CO2 resources, will be higher than those in the Gulf Coast region. Potential sources of CO2 in the Rocky Mountain region will require some degree of processing and may involve joint operations or purchase agreements with third parties, all of which will contribute to higher costs. These potentially higher costs attributable to CO2 do not include the expected benefit to be derived from the sale of methane and helium from Riley Ridge, which if included would make the cost of this CO2 competitive and potentially even less expensive than the CO2 at Jackson Dome, with the ultimate effect on our CO2 costs dependent on various factors such as the sales price for the methane and helium production. However, pipeline construction costs in the Rocky Mountain region are anticipated to be lower than those incurred in the Gulf Coast region due to differing geographic and regulatory factors.

While these economic factors have wide ranges, our rate of return from these operations has generally been higher than our rate of return on traditional oil and gas operations; thus, our tertiary operations have become our single most important area of focus. 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; thus, these operations will be the backbone of our growth for the foreseeable future. Although we believe that our plans and projections are reasonable and achievable, there could be delays or unforeseen problems in the future that could delay or affect the economics of our overall tertiary development program. We believe that such delays or price effects, if any, should only be temporary.

Financial Statement Impact of CO2 Operations. Our increasing emphasis on CO2 tertiary recovery projects has significantly impacted, and will continue to impact, our financial results and certain operating statistics. First, there is a significant delay between the initial capital expenditures on these fields and the resulting production increases. We must build facilities, and often a CO2 pipeline to the field, before CO2 flooding can commence, and it usually takes six to twelve months before the field responds to the injection of CO2 (i.e., oil production commences). Further, we may spend significant amounts of capital before we can recognize any proven reserves from fields we flood (see Analysis of CO2 Tertiary Recovery Operating Activities below). Even after a field has proven reserves, there will usually be significant amounts of additional capital required to fully develop the field.

Second, tertiary projects may be more expensive to operate than other oil fields because of the cost of injecting and recycling the CO2 (primarily due to the cost of the CO2 and the significant energy requirements to re-compress the CO2 back into a near-liquid state for re-injection purposes). The costs of our CO2 and the electricity required to recycle and inject this CO2 comprise almost half of our typical tertiary operating expenses. Since these costs vary along with commodity and electrical prices, they are highly variable and will increase in a high-commodity-price environment and decrease in a low-price environment. As an example (as discussed above), during the two-year period spanning 2010 and 2011 the cost of our CO2 varied from $0.20 per Mcf to $0.28 per Mcf. Most of our CO2 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 CO2 is injected, and 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 CO2 (following the commencement of tertiary oil production), the operating costs per barrel will be higher at the inception of CO2 injection projects because of minimal related oil production at that time.

Analysis of CO2 Tertiary Recovery Operating Activities. We project that our oil production from our CO2 operations will increase substantially over the next several years as we continue to expand our program by adding projects and phases. As of December 31, 2011, we had approximately 147.6 MMBbls of proved oil reserves related to tertiary operations, representing approximately 32% of our total corporate proved reserves, and we have identified and estimated significant additional oil potential in other fields that we own.

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. Our new CO2 flood at Oyster Bayou Field started production in late 2011, and Hastings Field began production in early 2012. The reservoir engineers will evaluate the production response to the CO2 injections and determine at what point we will be able to recognize proved reserves at these fields. Currently we anticipate recognizing proved reserves at these two fields by the end of 2012. Thus, the magnitude of proven reserves that we can book in any given year will depend on our progress with new floods and the timing of the production response from new floods and the performance of our existing floods.

Our average annual oil production from our CO2 tertiary recovery activities has increased over time, from an average of 3,970 Bbls/d in 2002 to 30,959 Bbls/d during 2011 (31,144 Bbls/d during the fourth quarter of 2011). Tertiary oil production represented approximately 48% of our continuing production during 2011 on a BOE basis. We expect that this tertiary-related oil production will continue to increase, although the increases are not always predictable or consistent. While we may have temporary fluctuations in oil production related to tertiary operations, this usually does not indicate any issue with the proved and potential oil reserves recoverable with CO2. A detailed discussion of each of our tertiary oil fields and the development of each is included in Item 1, Business and Properties.

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The following chart shows our tertiary oil production by field by quarter for 2011 and for the years ended December 31, 2011, 2010 and 2009:

	Average Daily Production (Bbl/d)						
	2011 Quarters						
	First	Second	Third	Fourth	Year Ended December 31,		
Tertiary Oil Field	Quarter	Quarter	Quarter	Quarter	2011	2010	2009
Phase 1:							
Brookhaven	3,664	3,213	3,030	3,121	3,255	3,429	3,416
McComb area	2,161	1,983	2,005	1,843	1,997	2,342	2,391
Mallalieu area	2,925	2,646	2,620	2,587	2,693	3,377	4,107
Other	3,290	3,196	2,879	2,749	3,026	3,202	2,306
Phase 2:							
Heidelberg	3,374	3,548	3,141	3,728	3,448	2,454	651
Eucutta	3,247	3,114	2,985	3,139	3,121	3,495	3,985
Soso	2,582	2,317	2,331	2,162	2,347	3,065	2,834
Martinville	500	416	453	481	462	720	877
Phase 3:							
Tinsley	6,567	6,990	7,075	6,338	6,743	5,584	3,328
Phase 4:							
Cranfield	991	1,085	1,214	1,200	1,123	911	448
Phase 5:							
Delhi	1,524	2,263	3,358	3,778	2,739	483	-
Phase 8:(1)							
Oyster Bayou	-	-	-	18	5	-	-
Total tertiary oil production (Bbl/d)	30,825	30,771	31,091	31,144	30,959	29,062	24,343
Tertiary lease operating expense per Bbl(2)	$ 24.93	$ 22.87	$ 24.91	$ 23.59	$ 24.08	$ 21.68	$ 21.14

(1) As of December 31, 2011, we did not have any tertiary production from our fields in Phases 6 and 7. Phase 6, Citronelle Field, will require an extension to the Free State CO2 Pipeline or another pipeline, depending on the ultimate CO2 source for this field, the timing of which is uncertain. Phase 7, Hastings Field, is currently being injected with CO2, with first tertiary oil response in early 2012.

(2) Included in tertiary operating expenses are certain prior period amounts that have been reclassified to conform with the current year presentation. See Note 1, Significant Accounting Policies, to the Consolidated Financial Statements for additional information regarding these reclassifications.

Oil production from our tertiary operations increased to an average of 30,959 Bbls/d during 2011, a 7% increase over our 2010 tertiary production level of 29,062 Bbls/d, primarily due to production growth in response to continued expansion of the tertiary floods in Delhi, Tinsley, Cranfield and Heidelberg fields. Offsetting 2011 production gains were declines in our more mature Phase 1 and Phase 2 fields (excluding Heidelberg). Tertiary oil production during the fourth quarter of 2011 was relatively flat compared to both the fourth quarter 2010 levels and third quarter 2011 levels. Oyster Bayou and Hastings Fields experienced their initial tertiary production response in late December 2011 and in late January 2012, respectively. We expect 2012 tertiary production to be positively impacted by increased production at these fields.

Oil production from our tertiary operations averaged 29,062 Bbls/d during 2010, a 19% increase over our 2009 tertiary production level of 24,343 Bbls/d. Tertiary oil production during the fourth quarter of 2010 averaged 31,139 Bbls/d, an 18% increase over the fourth quarter 2009 levels, and a 5% sequential increase from third quarter 2010 levels. These year-over-year increases were the result of production growth in response to continued expansion of the tertiary floods in our Tinsley, Heidelberg, Cranfield and Lockhart Crossing fields, and to initial production response from Delhi Field during 2010. Offsetting these production gains were declines in our Mallalieu and Eucutta Fields.

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 CO2, plateau temporarily, and then resume its 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 CO2, as the CO2 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 entire field is developed, albeit sometimes in inconsistent patterns. These types of fluctuations were most noticeable in 2011 at Tinsley and Heidelberg fields, two of our fields which have exhibited strong production growth in the recent past. At Tinsley Field, during the third quarter of 2011, we stopped CO_2 injections in parts of the field in order to address issues with wells that were improperly plugged by prior operators. At Heidelberg Field, we had to modify 39 wells in order to address conformance issues (i.e., to control the flow of the CO_2 to the desired geologic zone within the reservoir) during 2011. This conformance work caused a temporary decline in production at Heidelberg. Production during the fourth quarter of 2011 exceeded third quarter levels, but reduced our previously anticipated production growth during 2011. These temporary fluctuations have not changed our overall expectations of recovery in the Heidelberg and Tinsley fields.

During 2011, operating costs for our tertiary properties averaged $24.08 per Bbl, higher than the 2010 average of $21.68 per Bbl, which was in turn higher than the 2009 average of $21.14 per Bbl. Our higher per-barrel costs in 2011 were due primarily to higher workover, power, and facility and compressor repair expenses, plus higher CO_2 costs due to higher oil prices, to which CO_2 costs are partially tied. Our per-barrel costs in 2010 were higher than in 2009 due primarily to the higher cost of CO_2 during the period. Our single highest cost for our tertiary operations is our cost for fuel and utilities, which averaged $6.31 per Bbl in 2011, $5.93 per Bbl in 2010 and $5.76 per Bbl in 2009, which has increased on a per barrel basis due to the higher cost of these items, and the continued expansion of our tertiary floods. For any specific field, we expect our tertiary lease operating expense per BOE to be high initially and then decrease as production increases, ultimately leveling off until production begins to decline in the later life of the field, when lease operating expense per Bbl will again increase.

Operating Results

As summarized in the Overview section above, and discussed in further detail below, our operating results in 2011 were in many ways our best ever and have increased significantly over the last three years. As we controlled the general partner of ENP from the date of the Encore Merger until we sold our ownership interests in ENP on December 31, 2010, the operating results of ENP were consolidated with our results of operations for the year ended December 31, 2010, even though we only owned approximately 46% of ENP's common units. The primary factors impacting our operating results were fluctuating commodity prices, changes in the fair value of our oil and natural gas derivative contracts, increases and decreases in production, the Encore Merger and the subsequent sale of non-strategic legacy Encore assets and ENP ownership interests, which are all explained in more detail below.

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Certain of our operating results and statistics for each of the last three years are included in the following table. Included in the table are certain prior period amounts that have been reclassified to conform with the current year presentation. See Note 1, Significant Accounting Policies, to the Consolidated Financial Statements for additional information regarding these reclassifications.

	Year Ended December 31,		
In thousands, except per share and unit data	2011	2010 (1)	2009
Operating results			
Net income (loss) attributable to Denbury stockholders	$ 573,333	$ 271,723	$ (75,156)
Net income (loss) per common share - basic	1.45	0.73	(0.30)
Net income (loss) per common share - diluted	1.43	0.72	(0.30)
Net cash provided by operating activities	1,204,814	855,811	530,599
Average daily production volumes			
Bbls/d	60,736	59,918	36,951
Mcf/d	29,542	78,057	68,086
BOE/d(2)	65,660	72,927	48,299
Operating revenues			
Oil sales	$ 2,217,529	$ 1,661,380	$ 778,836
Natural gas sales	51,622	131,912	87,873
Total oil and natural gas sales	$ 2,269,151	$ 1,793,292	$ 866,709
Commodity derivative contracts(3)			
Cash receipt (payment) on settlement of commodity derivative contracts	$ 2,377	$ (31,612)	$ 146,734
Non-cash fair value adjustment income (expense)	50,120	53,026	(382,960)
Total income (expense) from commodity derivative contracts	$ 52,497	$ 21,414	$ (236,226)
Unit prices - excluding impact of derivative settlements			
Oil price per Bbl	$ 100.03	$ 75.97	$ 57.75
Natural gas price per Mcf	4.79	4.63	3.54
Unit prices - including impact of derivative settlements(3)			
Oil price per Bbl	$ 98.90	$ 71.69	$ 68.63
Natural gas price per Mcf	7.34	6.45	3.54
Oil and natural gas operating expenses			
Lease operating expenses	$ 507,397	$ 470,364	$ 314,689
Marketing expenses	26,047	31,036	16,890
Taxes other than income(4)	147,534	120,541	43,267

Oil and natural gas operating revenues and expenses per BOE(2)						
Oil and natural gas revenues	$	94.68	$	67.37	$	49.16
Lease operating expenses		21.17		17.67		17.85
Marketing expense		1.09		1.17		0.96
Taxes other than income(4)		6.16		4.53		2.45
Non-tertiary CO2 revenues and expenses						
CO2 sales and transportation fees	$	22,711	$	19,204	$	13,422
CO2 discovery and operating expenses(5)		(14,258)		(7,801)		(4,262)
CO2 revenue and expenses, net	$	8,453	$	11,403	$	9,160

(1) Includes the results of operations of Encore and ENP from March 9, 2010, through December 31, 2010.

(2) Barrel of oil equivalent using the ratio of one barrel of oil to six Mcf of natural gas (“BOE”).

(3) See also Market Risk Management below for information concerning the Company’s derivative transactions.

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(4) Includes $8.4 million, $5.6 million and $5.8 million of franchise taxes and property taxes on office buildings during 2011, 2010 and 2009, respectively.

(5) Includes $7.5 million of exploratory drilling costs in 2011.

Production

Average daily production by area for 2011, 2010 and 2009, and for each of the quarters of 2011, is shown below, as is our estimated pro forma production had the production from the properties acquired in the Encore Merger been included with our production for the entire first quarter of 2010:

	Average Daily Production (BOE/d)							
	First	Second	Third	Fourth	Year Ended December 31,			
Operating Area	Quarter 2011	Quarter 2011	Quarter 2011	Quarter 2011	2011	2010 (1)	Pro Forma 2010 (2)	2009
Gulf Coast region:								
Tertiary oil fields	30,825	30,771	31,091	31,144	30,959	29,062	29,062	24,343
Non-tertiary fields:								
Mississippi	5,930	5,642	5,636	4,746	5,486	6,505	6,505	8,343
Texas	4,371	4,202	4,096	3,868	4,133	4,941	4,941	2,615
Louisiana	511	454	47	141	287	517	517	476
Alabama and other	1,020	1,079	1,064	1,031	1,049	1,042	1,042	1,114
Total Gulf Coast region	42,657	42,148	41,934	40,930	41,914	42,067	42,067	36,891
Rocky Mountain region:								
Cedar Creek Anticline	9,163	8,925	8,930	8,858	8,968	7,930	9,728	-
Bakken	5,728	7,626	9,976	11,743	8,788	3,824	4,480	-
Bell Creek	890	936	889	840	889	802	979	-
Paradox	635	690	680	653	665	582	707	-
Other	2,613	2,693	2,689	2,533	2,631	2,362	2,891	-
Total Rocky Mountain region	19,029	20,870	23,164	24,627	21,941	15,500	18,785	-
Total Continuing Production	61,686	63,018	65,098	65,557	63,855	57,567	60,852	36,891
Properties disposed or to be disposed:								
Barnett Shale	-	-	-	-	-	-	-	9,539
Legacy Encore properties	-	-	-	-	-	6,556	9,852	-

ENP	-	-	-	-	-	7,098	8,767	-
Gulf Coast Non-Core Assets(3)	1,918	1,901	1,732	1,677	1,805	1,706	1,706	1,869
Total Production	63,604	64,919	66,830	67,234	65,660	72,927	81,177	48,299

(1) Includes production of Encore and ENP from the March 9, 2010, acquisition date through December 31, 2010, or in the case of non-strategic assets disposed, through the date the asset was sold.

(2) Represents pro forma production assuming we had reported the production from the Encore Merger between January 1, 2010 and March 8, 2010.

(3) Denbury has entered into a purchase and sale agreement to dispose of certain non-core Gulf Coast assets. The closing date of the sale is expected to occur in late February 2012.

As outlined in the above table, continuing production increased 6,288 BOE/d (11%) between 2010 and 2011, and increased 5% when including Encore's 2010 pre-merger production. The increases were primarily due to production increases from the Bakken and our tertiary oil fields (see a discussion of our tertiary operations in CO2 Operations above), offset by normal declines in most of our other non-tertiary properties. Total production decreased 10% year over year due primarily to the sale of non-strategic legacy Encore and ENP properties during 2010.

Production from our Bakken properties averaged 8,788 BOE/d during 2011, compared to 4,480 BOE/d during 2010, when including Encore's pre-merger production. The production increases in the Bakken are due to an acceleration of our drilling activities in the area, as we increased our operated drilling rigs from two at the time of the Encore acquisition in March 2010, to five at the beginning of 2011, seven at the end of the third quarter of 2011 and six at the end of 2011. During 2011, we drilled and completed 30 operated wells in the Bakken. Our Bakken production growth for the first half of 2011 was negatively impacted by severe winter weather and spring flooding, which caused delays in well completions and curtailments in oil production; however, with the increase in operated drilling rigs and good weather conditions, we have caught up on the backlog of our wells requiring fracturing treatment. We currently intend to begin 2012 with six operated rigs and then gradually decline to three rigs by mid-year. We may eventually decide to only reduce our Bakken rig count to four rigs if oil prices and hence operating cash flow exceeds our expectations.

Our production from the Cedar Creek Anticline generally declines in periods of increasing prices due to a net profits interest associated with this production; therefore, a portion of the decline in 2011 production at this field is related to the increase in oil prices during 2011.

Overall production for the fourth quarter of 2011 increased slightly from third quarter 2011 levels as increases in Bakken production offset normal declines in production from our other non-tertiary properties.

The increase in production from 2009 to 2010 is due primarily to the additional production from the properties acquired in the Encore Merger, a 19% increase in tertiary oil production and a full year of production from the Conroe Field acquisition, which closed in December 2009. Offsetting these increases were the Barnett Shale dispositions in 2009. Excluding production from the Barnett Shale properties sold during 2009 and production attributable to the non-strategic legacy Encore and ENP properties sold during 2010, production would have averaged 59,273 BOE/d during 2010 and 38,760 BOE/d during 2009, a 53% increase year to year.

Our production during 2011 was 93% oil as compared to 82% during 2010 and 77% during 2009. The increase in oil production percentage in 2011 is due to the sales of the non-strategic Encore and ENP properties during 2010, which had a higher percentage of natural gas production, and increases in our tertiary and Bakken production, which are primarily oil. The increase in oil production percentage in 2010 compared to 2009 is due to the sale of our natural gas-rich Barnett Shale properties in the second half of 2009, the acquisition of interests in the oil-rich Conroe Field in December 2009, and the increase in our tertiary operations, partially offset by the non-strategic natural gas properties that we acquired in the Encore Merger and subsequently sold during 2010.

Oil and Natural Gas Revenues

Although our production for 2011 declined from 2010 levels due to the asset sales discussed above, our oil and natural gas revenues increased significantly in the current period due to higher oil prices. Higher production and commodity prices resulted in an increase in our oil and natural gas revenue between 2009 and 2010. The changes in revenues due to these factors, excluding any impact of our derivative contracts, are reflected in the following table:

	Year Ended December 31, 2011 vs. 2010		Year Ended December 31, 2010 vs. 2009	
In thousands	Increase (decrease) in Revenues	Percentage Increase (decrease)	Increase in Revenues	Percentage Increase in Revenues

		in Revenues		
Change in revenues due to:				
Increase (decrease) in production	$ (178,709)	(10%)	$ 441,959	51%
Increase in commodity prices	654,568	37%	484,624	56%
Total increase in revenues	$ 475,859	27%	$ 926,583	107%

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Excluding any impact of our derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during 2011, 2010 and 2009:

	Year Ended December 31,		
	2011	2010	2009
Net Realized Prices:			
Oil price per Bbl	$100.03	$75.97	$57.75
Natural gas price per Mcf	4.79	4.63	3.54
Price per BOE	94.68	67.37	49.16
NYMEX Differentials:			
Oil per Bbl	$4.95	$(3.54)	$(4.21)
Natural gas per Mcf	0.76	0.23	(0.63)

Our oil price differentials improved $8.49 per Bbl, from $3.54 per Bbl below NYMEX in 2010 to $4.95 per Bbl above NYMEX in 2011, primarily due to the favorable price differential for crude oil sold under LLS index pricing. Prices received in a regional market can differ from NYMEX pricing due to a variety of reasons, including supply and/or demand factors and location differentials. NYMEX pricing, which has long been a benchmark price that reflects the economics in the U.S. midcontinent market, has been influenced in the recent past by significant increases in supply. Alternatively, the LLS market is reflective of market economics at the Gulf Coast, where both foreign and domestic oil is bought and sold, and correlates more closely to global oil prices. During the first quarter of 2011, the LLS index price began to increase significantly more than NYMEX prices, causing the LLS differential to increase to $9.28 per Bbl on a trade-month basis, and it continued to increase, reaching $15.32 per Bbl in the second quarter of 2011 and $18.90 per Bbl in the third quarter of 2011. During the fourth quarter of 2011, the LLS differential rose to a positive differential of $23.36 per Bbl above NYMEX but ended 2011 at $8.92 per Bbl above NYMEX. It is uncertain how long this LLS differential will remain at this level. Because our derivative contracts are based on NYMEX prices, those contracts do not impact the differential we receive. Overall, during 2011, we sold approximately (a) 45% of our crude oil based on the LLS index price, although due to contract provisions we may not realize the benefit of the full differential; (b) 28% based on NYMEX or West Texas Intermediate ("WTI") Posting plus Argus P+ prices; and (c) 27% based on various other indexes, most of which have also improved relative to WTI, but to a lesser degree.

Our Company-wide oil NYMEX differential improved during 2010 over our differential in 2009 primarily due to the 2009 sale of our Barnett Shale properties, where the natural gas liquids price was significantly below NYMEX oil prices, partially offset by the Rocky Mountain properties we acquired in the Encore Merger, which tend to have oil differentials worse than our historical corporate average.

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, these differentials are very seldom more than a dollar above or below NYMEX prices.

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Oil and Natural Gas Derivative Contracts

The following table summarizes the impact our oil and natural gas derivative contracts had on our operating results for 2011, 2010 and 2009:

	Non-Cash Fair Value Gain/(Loss)			Cash Settlements Receipt/(Payment)		
In thousands	2011	2010	2009	2011	2010	2009
Crude oil derivative contracts:						
First quarter	$ (167,064)	$ 61,821	$ (95,861)	$ (5,028)	$ (63,550)	$ 85,836
Second quarter	187,194	145,099	(189,318)	(16,972)	(13,829)	42,002
Third quarter	205,355	(62,450)	(20,850)	(1,857)	(3,590)	18,527
Fourth quarter	(166,505)	(100,029)	(69,721)	(1,271)	(12,448)	369
Full Year	$ 58,980	$ 44,441	$ (375,750)	$ (25,128)	$ (93,417)	$ 146,734
Natural gas derivative contracts:						
First quarter	$ (5,274)	$ 39,018	$ (10,490)	$ 6,616	$ 3,749	$ -
Second quarter	(3,348)	(19,909)	(5,473)	6,030	16,630	-
Third quarter	229	19,933	(1,434)	6,427	13,626	-
Fourth quarter(1)	(467)	(30,457)	10,187	8,432	27,800	-
Full Year	$ (8,860)	$ 8,585	$ (7,210)	$ 27,505	$ 61,805	$ -
Total commodity derivative contracts:						
First quarter	$ (172,338)	$ 100,839	$ (106,351)	$ 1,588	$ (59,801)	$ 85,836
Second quarter	183,846	125,190	(194,791)	(10,942)	2,801	42,002
Third quarter	205,584	(42,517)	(22,284)	4,570	10,036	18,527
Fourth quarter	(166,972)	(130,486)	(59,534)	7,161	15,352	369
Full Year	$ 50,120	$ 53,026	$ (382,960)	$ 2,377	$ (31,612)	$ 146,734

(1) Natural gas derivative settlements for the fourth quarter of 2010 include receipts of $10.0 million related to the monetization of natural gas swaps that were unwound due to the sale of our Haynesville and East Texas assets.

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.

Production Expenses

Lease operating expenses increased $37.0 million (8%), from $470.4 million in 2010 to $507.4 million in 2011, primarily due to an 18% increase in our tertiary operating expenses, from $229.9 million to $272.1 million, partially offset by a $5.1 million or 2% decrease in our non-tertiary operating expenses. The increase in our tertiary operating expenses is further discussed under CO2 Operations above. The decrease in our non-tertiary operating costs is primarily due to the sale of non-strategic Encore assets during 2010, which reduced our lease operating costs by $44.1 million, partially offset by higher operating costs in our Rocky Mountain region. Increases in our Rocky Mountain region operating expenses are primarily attributable to (1) the 2010 period being approximately ten months, as the properties were acquired in early March 2010, (2) the Cedar Creek Anticline, where we experienced higher workover costs in 2011 compared to 2010, and (3) the Bakken, where production has increased significantly since 2010 due to new wells.

Our lease operating expense on a per BOE basis increased $3.50 (20%), from $17.67 in 2010 to $21.17 in 2011, primarily due to the sale of non-strategic Encore and ENP properties from May 2010 through December 2010, which were primarily natural gas properties that generally had a lower operating cost per BOE than Denbury's legacy properties, and to higher tertiary operating costs per BOE, which are further discussed under CO2 Operations above.

Lease operating expense increased by 49% in absolute dollars between 2009 and 2010 but decreased 1% on a per BOE basis. The increase on an absolute basis was primarily attributable to the properties acquired in the Encore Merger and further expansion of our tertiary operations, partially offset by the 2009 sale of our Barnett Shale properties. The decrease on a per BOE basis was primarily due to the Encore Merger, as the assets acquired generally had a lower lease operating expense per BOE than Denbury's legacy properties, of which the majority are CO2 enhanced oil recovery properties.

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Taxes other than income, which increased by 36% on a per BOE basis between 2010 and 2011 and 85% on a per BOE basis between 2009 and 2010, includes ad valorem, production and franchise taxes. The increase in each period is largely attributable to an increase in production taxes, which generally fluctuate in line with oil and natural gas revenues.

General and Administrative Expenses ("G&A")

	Year Ended December 31,		
In thousands, except per BOE data and employees	2011	2010	2009
Administrative costs	$246,112	$231,280	$143,200
Stock-based compensation	39,875	33,926	24,322
Founder's retirement compensation	-	-	10,000
Incentive compensation for Genesis management	-	1,149	14,212
Operator labor and overhead recovery charges	(125,466)	(112,160)	(76,044)
Capitalized exploration and development costs	(34,996)	(20,074)	(13,905)
Net G&A expense	$125,525	$134,121	$101,785
G&A per BOE:			
Administrative costs, net	$3.98	$3.95	$3.23
Stock-based compensation, net	1.26	1.05	1.16
Founder's retirement compensation	-	-	0.57
Incentive compensation for Genesis management	-	0.04	0.81
Net G&A expense	$5.24	$5.04	$5.77
Employees as of December 31	1,308	1,195	830

Administrative costs increased $14.8 million, or 6%, between 2010 and 2011, and increased $88.1 million, or 62%, between 2009 and 2010. The increase in 2011 compared to 2010 is primarily due to increased expense resulting from the Encore Merger, as the 2010 period includes the effect of the Encore Merger beginning on the acquisition date, March 9, 2010. The number of employees at December 31, 2011 represents a 53% increase over our headcount prior to the Encore Merger, which was 856 employees. Additional expense attributable to the legacy Encore office leases and the new Denbury headquarters lease, together with related moving costs, and additional compensation related to the resignation of our former President and Chief Operating Officer also contributed to the higher administrative costs during 2011. A decrease in expense related to the Company's discretionary annual bonus plan during 2011 was offset by an increase in salary expenses, which is primarily attributable to an increase in the number of employees during 2011. The increase in administrative costs during 2011 was partially offset by a reduction in professional services incurred primarily due to the 2010 period being unusually high because of integration activities related to the Encore Merger. Stock-based compensation costs increased during 2011 primarily due to the increased number of employees during 2011 as compared to 2010. Stock-based compensation, net of amounts reclassified to field operations or capitalized, were approximately $30.3 million in 2011, $27.9 million in 2010 and $20.5 million in 2009.

The increase in administrative and stock-based compensation costs during 2011 was partially offset by an increase in operator overhead recovery charges. 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 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 gas production and development activities. As a result of additional operated wells and drilling activities, additional tertiary operations and increased compensation expense, the amount we recovered as operator labor and overhead charges increased by 12% between 2010 and 2011. Capitalized exploration and development costs also increased between the periods, primarily due to increased compensation costs subject to capitalization.

Administrative costs increased between 2009 and 2010 primarily due to the Encore Merger, including higher compensation and personnel-related costs associated with a 44% increase in the number of employees between respective year-ends, increased third-party professional services fees and higher office operating expenses attributable to the legacy Encore and new Denbury headquarters office leases. Stock-based compensation increased 39% during 2010, as compared to 2009, due to an increase in the number of employees and changes in the mix of compensation awarded to employees. Increases to administrative costs and stock-based compensation were partially offset by the reduction in 2010 of charges associated with the nonrecurring compensation agreements between the Company and 1) its founder and former CEO and 2) certain members of Genesis management. Recovery of operator and labor charges and capitalization of exploration and development costs also increased during 2010 compared to 2009, primarily due to increased drilling activity and higher compensation costs.

The net effect was a 6% decrease in net G&A expense between 2010 and 2011, and a 32% increase in net G&A expense between 2009 and 2010. On a per BOE basis, net G&A expense increased 4% in 2011 compared to 2010, and decreased 13% in 2010 compared to 2009, primarily due to changes in production and the lack of non-recurring charges in 2010 as compared to 2009, as discussed above.

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Interest and Financing Expenses

In thousands, except per BOE data and interest rates	Year Ended December 31, 2011	2010	2009
Cash interest expense	$ 207,727	$ 221,759	$ 108,629
Non-cash interest expense	18,219	21,169	7,397
Less: Capitalized interest	(61,586)	(66,815)	(68,596)
Interest expense	$ 164,360	$ 176,113	$ 47,430
Interest income and other income	$ 17,462	$ 7,758	$ 9,019
Net cash interest expense and other income per BOE (1)	$ 5.42	$ 5.67	$ 2.14
Average debt outstanding	$ 2,470,682	$ 2,736,634	$ 1,265,142
Average interest rate (2)	8.4 %	8.1 %	8.6 %

(1) Cash interest expense less capitalized interest less interest and other income on BOE basis.

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

Interest expense decreased $11.8 million, or 7%, between 2011 and 2010, and increased $128.7 million, or 271%, between 2009 and 2010. Interest expense decreased between 2010 and 2011 primarily due to a decrease in average debt outstanding. Our debt level increased in early 2010 as a result of the Encore Merger and decreased throughout 2010 and in early 2011, as we repaid debt with proceeds from the sale of non-strategic legacy Encore assets and our ENP ownership interests. Also, in early 2011 we refinanced $525 million of our 7½% senior subordinated debt with $400 million of our 6 % senior subordinated debt, decreasing our debt outstanding and interest rate. Capitalized interest decreased 8% between 2010 and 2011 due to a reduction in capitalized interest on the Green Pipeline, which was placed in service during 2010, offset by incremental capitalized interest on CO2 floods, Riley Ridge and the Greencore Pipeline.

The increase in interest expense between 2009 and 2010 is due to the increase in our average debt outstanding to finance the Encore Merger, which closed in March 2010. Interest capitalized during 2010 was comparable to the 2009 amount due to the continued construction of the Green Pipeline through most of that year.

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

In thousands, except per BOE data	Year Ended December 31, 2011	2010	2009
Depletion and depreciation of oil and natural gas properties	$362,788	$394,957	$203,719
Depletion and depreciation of CO2 properties	18,220	20,665	18,052
Asset retirement obligations	6,287	6,443	3,280
Depreciation of other fixed assets	21,901	21,860	13,272
Cumulative change due to revision in policy for CO2 properties	-	(9,618)	-
Total DD&A	$409,196	$434,307	$238,323
DD&A per BOE:			
Oil and natural gas properties	$15.40	$15.08	$11.74
CO2 and other fixed assets	1.67	1.60	1.78

Cumulative change due to revision in policy for CO2 properties	-	(0.36)	-
Total DD&A cost per BOE	$17.07	$16.32	$13.52

We adjust our DD&A rate each quarter for significant changes in our estimates of oil and natural gas reserves and costs; thus, our DD&A rate has changed significantly, and it may continue to change in the future. Depletion of oil and natural gas properties decreased on an absolute-dollars basis during 2011 as compared to 2010, primarily due to the sale of non-strategic legacy Encore assets and our ownership interests in ENP during 2010. Depletion of oil and gas properties increased on a per BOE basis during 2011 compared to 2010, primarily due to higher costs per barrel associated with our larger 2011 Bakken capital program and upward revisions in estimated future development costs, also primarily relating to the Bakken assets, offset in part by natural gas reserves added from the Riley Ridge acquisition, which were purchased at a low cost per Mcf.

Depletion of oil and natural gas properties increased on both a per BOE basis and an absolute-dollars basis from 2009 to 2010, primarily due to the fact that the properties acquired in the Encore Merger were recorded at fair market value as required by the FASC Business Combinations topic, resulting in a higher rate than our historical DD&A rate. In addition, the sale of our Barnett Shale assets in 2009 and the acquisition of Conroe Field in late 2009 also increased our DD&A rate. Our proved reserves totaled 461.9 MMBOE at December 31, 2011, compared to 397.9 MMBOE at December 31, 2010, and 207.5 MMBOE at December 31, 2009.

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During 2011, we added approximately 88.0 MMBOE of proved reserves (before netting out 2011 production). The most significant additions were 48.2 MMBOE from the development of Bakken properties, approximately 39.5 MMBOE of natural gas reserves added through the acquisition of Riley Ridge, and 2.7 MMBOE related to commodity price revisions. Our tertiary oil reserves were approximately the same between 2011 and 2010 after adjusting for the 2011 production. We currently expect to book initial proved tertiary reserves for our new tertiary floods at Oyster Bayou and Hastings Fields by the end of 2012. The increase in our proved reserves from December 31, 2009 to December 31, 2010 was primarily due to the acquisition of Encore, development of Bakken properties and the acquisition of Riley Ridge interests in 2010.

Our DD&A expense for our CO2 assets decreased in 2011 compared to 2010, due to CO2 reserve increases at Jackson Dome at the end of 2010. On a per BOE basis, DD&A expense for our CO2 assets and other fixed assets increased in 2011 compared to that in the prior year period due to decreased oil and natural gas production volumes as a result of the sale of non-strategic Encore properties and our interests in ENP during 2010. Our DD&A expense for our CO2 and other fixed assets increased in 2010 compared to 2009 due primarily to other fixed assets added in the Encore Merger. However, our DD&A rate on a per BOE basis decreased approximately 10% between 2009 and 2010 as a result of increased oil and natural gas production volumes as a result of the Encore Merger and as a result of the proved CO2 reserves added at Jackson Dome and Riley Ridge late in 2010.

During the third quarter of 2010, we changed our method of accounting for CO2 properties and recorded a one-time, non-cash net reduction of $9.6 million ($6.0 million after tax) to DD&A expense for the period, which reflects the cumulative impact of the revised accounting policy on our historical financials. See Note 1, Significant Accounting Policies, to the Consolidated Financial Statements for additional information regarding this change.

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 a 12-month average price based on the first-day price of every month during the period. We did not have a ceiling test write-down during 2011, 2010 or 2009. However, if oil prices were to decrease significantly in subsequent periods, we may be required to record write-downs under the full cost pool ceiling test in the future. The possibility and amount of any future write-down is difficult to predict and will depend upon oil and natural gas prices, the incremental proved reserves that may be added each period, revisions to previous estimates of reserves and future capital expenditures, and additional capital spent.

Encore Transaction and Other Costs and Impairment of Assets

The FASC Business Combinations topic requires that all transaction costs (advisory, legal, accounting, due diligence, integration, third-party fees, etc.) be expensed as incurred. We recognized a total of $4.4 million, $92.3 million, and $8.5 million of transaction and other costs during 2011, 2010, and 2009, respectively, associated with the Encore Merger, including $3.6 million and $43.8 million during 2011 and 2010, respectively, related to severance costs.

During 2011, we evaluated a potential CO2 resource with known probable CO2 reserves and upon completing our evaluation, we determined the potential resource did not produce reserves in a quantity or at a cost that would benefit our tertiary oil operations. Accordingly, we impaired the related capitalized costs at December 31, 2011, resulting in a charge of $16.6 million, which is classified as “Impairment of Assets in the Consolidated Statement of Operations.”

At December 31, 2011, the Company also recorded an other-than-temporary impairment on our investment in Vanguard common units. The $6.3 million impairment charge reduces our investment in the Vanguard common units to their trading value as of December 31, 2011 and is classified as “Impairment of Assets” on the Consolidated

Statement of Operations. The units were subsequently sold during January 2012. See Note 14, Subsequent Events, in the Consolidated Financial Statements.

Income Taxes

	Year Ended December 31,		
Amounts in thousands, except per BOE amounts and tax rates	2011	2010	2009
Current income tax expense	$8,249	$33,194	$4,611
Deferred income tax expense (benefit)	342,463	160,349	(51,644)
Total income tax expense (benefit)	$350,712	$193,543	$(47,033)
Average income tax expense (benefit) per BOE	$14.63	$7.27	$(2.67)
Effective tax rate	38.0%	40.4%	38.5%
Total net deferred tax liability	$1,868,420	$1,520,538	$469,195

Our income tax provision for each of the last three years has been based on an estimated statutory rate of approximately 38%. Our 2011 effective tax rate was consistent with our estimated statutory rate during the year, as nondeductible expenses were offset by the recognition of additional tax benefits in our 2010 tax returns in excess of the estimated benefits included in our tax provision at December 31, 2010. Our 2010 effective tax rate was higher than our estimated statutory rate due to the recognition of additional net tax expense on the revaluation of our deferred taxes at the date of the Encore Merger and as a result of our legal entity restructuring at December 31, 2010. During 2011, 2010 and 2009, current income tax expense represents our anticipated alternative minimum cash taxes that we cannot offset with enhanced oil recovery credits, as well as state income taxes. Offsetting current income tax expense during 2011 was a net benefit due to the change in treatment for certain items between our 2010 tax provision and our 2010 filed tax return. This change in treatment resulted in a reclassification of approximately $16.9 million from current to deferred taxes.

The significant increase in our total net deferred tax liability in 2010 compared to 2009 is primarily due to the Encore Merger, in which Encore's net deferred tax liability and tax attributes carried over to us. As of December 31, 2011, we had an estimated $53.4 million of enhanced oil recovery credits to carry forward that can be utilized to reduce our current income taxes during 2012 or future years. These enhanced oil recovery credits do not begin to expire until 2023. 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 decrease significantly from current levels.

Proposals contained in the President's recently introduced budget, along with legislation introduced in Congress, attempt to remove many tax incentives for the oil and gas industry. Those items that would have the most significant impact on us would include the loss of the domestic manufacturing deduction as well as the repeal of the immediate expensing of intangible drilling costs and tertiary injectant costs. It is uncertain whether or not the current administration or Congress will be successful in changing these tax provisions, but if they were successful, it would likely increase the amount of cash taxes that we pay. Should cash taxes increase significantly, it could impact our forecasted 2012 or later year capital expenditures.

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.

	Year Ended December 31,		
Per BOE data	2011	2010	2009
Oil and natural gas revenues	$ 94.68	$ 67.37	$ 49.16
Gain (loss) on settlements of derivative contracts	0.10	(1.19)	8.32
Lease operating expenses	(21.17)	(17.67)	(17.85)
Marketing expenses	(1.09)	(1.17)	(0.96)
Production netback	72.52	47.34	38.67
CO_2 sales, net of operating expenses	0.36	0.43	0.51
Taxes other than income (1)	(6.16)	(4.53)	(2.45)
General and administrative expenses	(5.24)	(5.04)	(5.77)
Transaction costs and other related to the Encore Merger	(0.18)	(3.47)	(0.48)
Net cash interest expense and other income	(5.42)	(5.67)	(2.14)
Other	0.86	0.03	2.30
Changes in assets and liabilities relating to operations	(6.47)	3.06	(0.54)
Cash flow from operations	50.27	32.15	30.10
DD&A	(17.07)	(16.32)	(13.52)
Deferred income taxes	(14.29)	(6.02)	2.93
Gain on sale of interests in Genesis	-	3.81	-

Loss on early extinguishment of debt		(0.67	)		-		-	
Non-cash commodity derivative adjustments		2.09			1.99		(21.72	)
Net income attributable to noncontrolling interest		-			(0.52	)	-	
Other non-cash items		3.59			(4.88	)	(2.05	)
Net income (loss)	$	23.92		$	10.21	$	(4.26	)

(1) "Taxes other than income" includes production taxes related to oil and natural gas production of \$5.23, \$3.76 and \$1.45 during 2011, 2010 and 2009, respectively

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, 2011, we had $385 million in outstanding borrowings on our bank credit facility. None of our existing debt

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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 under the lease. 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, 2011.

In thousands	2014	2015	2016	2017	2020	2021	Total	Fair Value
Variable rate debt:								
Bank credit facility (weighted average interest rate of 2.03% at December 31, 2011)	$ -	$ -	$ 385,000	$ -	$	$	$ 385,000	$ 385,000
Fixed rate debt:								
9½% Senior Subordinated Notes due 2016	-	-	224,920	-	-	-	$ 224,920	$ 247,974
9¾% Senior Subordinated Notes due 2016	-	-	426,350	-	-	-	426,350	470,051
8¼% Senior Subordinated Notes due 2020	-	-	-	-	996,273	-	996,273	1,113,335
6 % Senior Subordinated Notes due 2021						400,000	400,000	418,000
Other Subordinated Notes	1,072	485	-	2,250	-	-	3,807	3,807

See Note 5, Long-Term Debt, to the Consolidated Financial Statements for details regarding our long-term debt.

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. We do not hold or issue derivative financial instruments for trading purposes. These contracts have consisted of price floors, collars and fixed price swaps. 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. We currently employ a strategy to hedge a portion of our forecasted production approximately a year and a half in the future from the current quarter, as we believe it is important to protect our future cash flow for a short period of time in order to give us time to adjust to commodity price fluctuations, particularly since many of our expenditures have long lead times. See Note 9, Derivative Instruments and Hedging Activities, 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. 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 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, 2011, our derivative contracts were recorded at their fair value, which was a net asset of approximately $6.1 million (excluding $4.1 million of deferred premiums that Denbury is obligated to pay for its derivative contracts, which payments are not subject to changes in commodity prices), a significant change from the $44.0 million net liability recorded at December 31, 2010 (excluding $26.7 million of deferred premiums). This change is primarily related to the expiration of oil derivative contracts during 2011, and to the oil and natural gas futures prices as of December 31, 2011, in relation to the new commodity derivative contracts we entered into during 2011 for future periods.

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Commodity Derivative Sensitivity Analysis

Based on NYMEX crude oil and natural gas futures prices as of December 31, 2011, and assuming both a 10% increase and decrease thereon, we would expect to make or receive payments on our crude oil and natural gas derivative contracts as shown in the following table:

In thousands	Crude Oil Derivative Contracts Receipt/ (Payment)	Natural Gas Derivative Contracts Receipt/ (Payment)
Based on:		
NYMEX futures prices as of December 31, 2011	$(4,071)	$24,691
10% increase in prices	(35,231)	22,381
10% decrease in prices	(1,810)	27,009

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 FASB guidance under 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 the 12-month 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 changes in ownership interests, payouts, joint venture audits, re-allocations by the purchaser/pipeline, 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, Denbury’s annual revisions to its reserve estimates have averaged approximately 1.6% of the previous year’s estimates and have been both positive and negative.

Changes in commodity prices also affect our reserve quantities. Between 2009 and 2010, commodity prices increased, resulting in an additional increase in our proved reserves of 2.9 MMBOE. Between 2010 and 2011, oil prices increased, resulting in an additional increase in our proved reserves of 2.6 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 2011 DD&A rate from $17.76 per BOE to approximately $17.02 per BOE, and a 5% decrease in our proved reserve quantities would have increased our DD&A rate to approximately $18.59 per BOE. Also, reserve quantities and their ultimate values, determined solely by our banks, are the primary factors in determining the 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 the sum of (1) the present value of estimated future net revenues from proved reserves before future abandonment costs (discounted at −−10%), based on unescalated period-end oil and natural gas prices during the first three quarters of 2009; and beginning in the fourth quarter of 2009, the average first-day-of-the-month oil and natural gas price for each month during the 12-month periods ended December 31, 2009, 2010 and 2011; (2) plus the cost of properties not being amortized; (3) plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; (4) less 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 CO2 reserves nor for those related to the cost of constructing CO2 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 the Company's capitalized CO2 costs related to CO2 reserves and CO2 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 2011, 2010 or 2009. Commodity prices increased between 2009 and 2010. Crude oil prices continued to increase during 2011, with NYMEX oil prices at year-end 2011 at $98.83 per Bbl, but natural gas prices began to decline in the second half of 2011, with NYMEX natural gas prices at $2.99 per Mcf at December 31, 2011. Commodity prices have historically been volatile and are expected to continue to be so in the future. If oil and natural gas prices should decrease, we may be required to record write-downs due to the full cost ceiling test. The amount of any future write-down is difficult to predict and will depend upon the oil and natural gas prices utilized in the ceiling test, the incremental proved reserves that might be added during each period and additional capital spent.

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 CO2 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 CO2 we produce (or acquire) and inject are principally our 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 CO2 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 CO2 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 2011, 2010 and 2009, we capitalized $65.3 million, $20.5 million and $8.0 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 file 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, 2011, we believe that all of our deferred tax assets recorded on our Consolidated Balance Sheet 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 (benefit) by approximately $9.2 million, $4.8 million and $(1.2) million for the years ended December 31, 2011, 2010 and 2009, respectively. See Note 6, Income Taxes, to the Consolidated Financial Statements and see 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 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 Measurements and Disclosures 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 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. The valuation of oil and natural gas properties is even more difficult due to the nature of our core business, enhanced oil recovery operations. In order to appropriately apply the FASC standard, we must estimate what value a third-party market participant would place on the acquired property. It is very subjective as to what value another entity would place on the potential barrels recoverable with CO2, which impacts our allocation of the purchase price to goodwill, unevaluated properties and proved properties. Although we find that this standard is difficult to apply in our circumstance, we use all available information to make these fair value determinations and, for certain acquisitions, engage third-party consultants for assistance.

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 September 2011, the FASB amended its guidance on goodwill impairment testing to permit an entity to first assess qualitative factors to determine whether it is more likely than not the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test. We adopted this guidance during 2011.

Each period 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 1 of the 2-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 1 of the 2-step quantitative goodwill impairment test.

Fair value calculated for the purpose of testing for impairment of our goodwill is estimated using the expected present value of future cash flows method and comparative market prices when appropriate. A significant amount of judgment is involved in performing these fair value estimates for goodwill, since the results are based on forecasted assumptions. Significant assumptions 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 CO2, projected recovery factors of tertiary reserves and risk-adjusted discount rates. We base 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 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 or collars, and fixed price swaps. We do not designate these derivative commodity contracts as hedge instruments for accounting purposes under the FASC Derivatives and Hedging topic. This means that any changes in the future fair value of these derivative contracts will be charged to 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. During 2011, 2010 and 2009, we recognized expense (income) of $(50.1) million, $(53.0) million and $383.0 million, respectively, related to non-cash changes in the fair market value of our derivative contracts.

Use of Estimates

See Note 1, Significant Accounting Policies, to the Consolidated Financial Statements for a discussion of the Company's use of estimates.

Recent Accounting Pronouncements

See Note 1, Significant Accounting Policies, to the Consolidated Financial Statements for a discussion of the effects of recently issued and recently adopted accounting pronouncements.

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Denbury Resources Inc.

Management's Discussion and Analysis of Financial Condition and Results of Operations

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 "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, forecasted capital expenditures, drilling activity or methods including the timing and location thereof, acquisition plans and proposals and dispositions, development activities, cost savings, capital budgets, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO2 reserves, helium reserves, potential reserves, percentages of recoverable original oil in place, hydrocarbon prices, pricing or cost assumptions based on current and projected oil and gas prices, liquidity, cash flows, availability of capital, borrowing capacity, regulatory matters, prospective legislation affecting the oil and gas industry, mark-to-market values, 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 word 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 the Company's 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 or on behalf of the Company. Among the factors that could cause actual results to differ materially are fluctuations of the prices received or demand for the Company's 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 the Company's other public reports, filings and public statements.

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Denbury Resources Inc.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

Item 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of 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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (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.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Dallas, Texas
February 28, 2012

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Denbury Resources Inc.

Consolidated Balance Sheets

(In thousands, except par value and share data)

	December 31, 2011	December 31, 2010
Assets		
Current assets		
Cash and cash equivalents	$ 18,693	$ 381,869
Accrued production receivable	294,689	223,584
Trade and other receivables, net	164,446	103,094
Short-term investments	86,682	93,020
Derivative assets	47,402	24,242
Deferred tax assets	50,156	27,454
Other current assets	22,045	11,055
Total current assets	684,113	864,318
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved	7,026,579	6,042,442
Unevaluated	1,157,106	870,130
CO2 properties	596,003	522,091
Pipelines and plants	1,701,756	1,378,239
Other property and equipment	157,674	121,973
Less accumulated depletion, depreciation, amortization and impairment	(2,627,493)	(2,197,517)
Net property and equipment	8,011,625	6,737,358
Derivative assets	29	12,919
Goodwill	1,236,318	1,232,418
Other assets	252,339	218,050
Total assets	$ 10,184,424	$ 9,065,063
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 429,336	$ 350,068
Oil and gas production payable	197,092	143,145
Derivative liabilities	26,523	78,184
Current maturities of long-term debt	8,316	7,948
Total current liabilities	661,267	579,345
Long-term liabilities		
Long-term debt, net of current portion	2,669,729	2,416,208
Asset retirement obligations	88,726	81,290
Derivative liabilities	18,872	29,687
Deferred taxes	1,918,576	1,547,992
Other liabilities	20,756	29,834
Total long-term liabilities	4,716,659	4,105,011

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; 402,946,070 and 400,291,033 shares issued at December 31, 2011 and 2010, respectively		403		400
Paid-in capital in excess of par		3,090,374		3,045,937
Retained earnings		1,909,475		1,336,142
Accumulated other comprehensive loss		(418)		(488)
Treasury stock, at cost, 13,965,673 and 78,524 shares at December 31, 2011 and 2010, respectively		(193,336)		(1,284)
Total stockholders' equity		4,806,498		4,380,707
Total liabilities and stockholders' equity	$	10,184,424	$	9,065,063

See accompanying Notes to Consolidated Financial Statements.

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Denbury Resources Inc.

Consolidated Statements of Operations

(In thousands, except per share data)

	Year ended December 31, 2011	2010	2009
Revenues and other income			
Oil, natural gas, and related product sales	$2,269,151	$1,793,292	$866,709
CO2 sales and transportation fees	22,711	19,204	13,422
Gain on sale of interests in Genesis	-	101,537	-
Interest income and other income	17,462	7,758	9,019
Total revenues and other income	2,309,324	1,921,791	889,150
Expenses			
Lease operating expenses	507,397	470,364	314,689
Marketing expenses	26,047	31,036	16,890
CO2 discovery and operating expenses	14,258	7,801	4,262
Taxes other than income	147,534	120,541	43,267
General and administrative	125,525	134,121	101,785
Interest, net of amounts capitalized of $61,586, $66,815 and $68,596, respectively	164,360	176,113	47,430
Depletion, depreciation and amortization	409,196	434,307	238,323
Derivatives expense (income)	(52,497)	(23,833)	236,226
Loss on early extinguishment of debt	16,131	-	-
Transaction and other costs related to the Encore Merger	4,377	92,271	8,467
Impairment of assets	22,951	-	-
Total expenses	1,385,279	1,442,721	1,011,339
Income (loss) before income taxes	924,045	479,070	(122,189)
Income tax provision (benefit)			
Current income taxes	8,249	33,194	4,611
Deferred income taxes	342,463	160,349	(51,644)
Consolidated net income (loss)	573,333	285,527	(75,156)
Less: net income attributable to noncontrolling interest	-	(13,804)	-
Net income (loss) attributable to Denbury stockholders	$573,333	$271,723	$(75,156)
Net income (loss) per common share – basic	$1.45	$0.73	$(0.30)
Net income (loss) per common share – diluted	$1.43	$0.72	$(0.30)
Weighted average common shares outstanding			
Basic	396,023	370,876	246,917
Diluted	400,958	376,255	246,917

See accompanying Notes to Consolidated Financial Statements.

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Denbury Resources Inc.

Consolidated Statements of Cash Flows

(In thousands)

	Year Ended December 31, 2011	2010	2009
Cash flow from operating activities:			
Consolidated net income (loss)	$573,333	$285,527	$(75,156)
Adjustments needed to reconcile to net cash flow provided by operations:			
Depletion, depreciation and amortization	409,196	434,307	238,323
Deferred income taxes	342,463	160,349	(51,644)
Gain on sale of interests in Genesis	-	(101,537)	-
Stock-based compensation	33,190	35,366	35,581
Non-cash fair value derivative adjustments	(50,008)	(55,445)	383,072
Loss on early extinguishment of debt	16,131	-	-
Founder’s retirement compensation	-	-	6,350
Amortization of debt issuance costs and discounts	16,954	17,876	7,215
Impairment of assets	22,951	-	-
Other, net	(4,302)	(2,144)	(3,704)
Changes in assets and liabilities, net of effects from acquisitions:			
Accrued production receivable	(74,781)	2,426	(52,863)
Trade and other receivables	(55,470)	24,977	12,681
Other current and long-term assets	(15,817)	(4,119)	(559)
Accounts payable and accrued liabilities	(35,462)	48,549	25,673
Oil and natural gas production payable	54,391	15,565	4,385
Other liabilities	(27,955)	(5,886)	1,245
Net cash provided by operating activities	1,204,814	855,811	530,599
Cash flow used for investing activities:			
Oil and natural gas capital expenditures	(1,082,853)	(671,574)	(343,351)
Acquisitions of oil and natural gas properties	(35,305)	(25,672)	(452,795)
Cash paid in Encore Merger and Riley Ridge acquisitions	(199,263)	(947,241)	-
CO2 capital expenditures	(84,789)	(93,556)	(100,358)
Pipelines and plants capital expenditures	(236,133)	(207,536)	(566,014)
Purchases of other assets	(28,838)	(28,684)	(13,591)
Net proceeds from sale of interests in Genesis	-	162,619	-
Net proceeds from sales of oil and natural gas properties and equipment	69,370	1,458,029	516,814
Other	(8,147)	(1,165)	(10,419)
Net cash used for investing activities	(1,605,958)	(354,780)	(969,714)
Cash flow provided by (used for) financing activities:			
Bank repayments	(330,000)	(1,530,000)	(856,000)
Bank borrowings	715,000	1,114,000	906,000
Repayment of senior subordinated notes	(525,000)	(609,424)	-
Premium paid on repayment of senior subordinated notes	(13,137)	(7,213)	-
Net proceeds from issuance of senior subordinated notes	400,000	1,000,000	389,827
Net proceeds from issuance of common stock	15,920	13,065	12,991
Costs of debt financing	(13,123)	(76,251)	(10,080)
ENP distributions to noncontrolling interest	-	(36,738)	-
Stock repurchase program	(195,227)	-	-

Other	(16,465)	(7,192)	(101)
Net cash provided by (used for) financing activities	37,968	(139,753)	442,637
Net increase (decrease) in cash and cash equivalents	(363,176)	361,278	3,522
Cash and cash equivalents at beginning of year	381,869	20,591	17,069
Cash and cash equivalents at end of year	$18,693	$381,869	$20,591

See accompanying Notes to Consolidated Financial Statements.

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Denbury Resources Inc.

Consolidated Statements of Changes in Stockholders' Equity

(Dollar amounts in thousands)

	Common Stock ($.001 Par Value)		Paid-In Capital in Excess of	Retained	Accumulated Other Comprehensive Income	Treasury Stock (at cost)		Denbury Stockholders'	Noncontrolling	Total
	Shares	Amount	Par	Earnings	(Loss)	Shares	Amount	Equity	Interest	Equity
Balance – December 31, 2008	248,005,874	$248	$707,702	$1,139,575	$(627)	446,287	$(6,830)	$1,840,068	$-	$1,840,068
Repurchase of common stock	-	-	-	-	-	194,943	(3,014)	(3,014)	-	(3,014)
Issued pursuant to employee stock purchase plan	-	-	(81)	-	-	(484,946)	7,417	7,336	-	7,336
Issued pursuant to employee stock option plan	1,312,714	2	5,651	-	-	-	-	5,653	-	5,653
Issued pursuant to directors' compensation plan	21,658	-	322	-	-	-	-	322	-	322
Issued pursuant to Conroe Field acquisition	11,620,000	12	168,711	-	-	-	-	168,723	-	168,723
Restricted stock grants	1,032,895	-	-	-	-	-	-	-	-	-
Restricted stock grants – forfeited	(63,849)	-	-	-	-	-	-	-	-	-
Stock-based compensation	-	-	24,322	-	-	-	-	24,322	-	24,322
Income tax benefit from equity awards	-	-	3,913	-	-	-	-	3,913	-	3,913
Derivative contracts, net	-	-	-	-	70	-	-	70	-	70
Net income	-	-	-	(75,156)	-	-	-	(75,156)	-	(75,156)
Balance – December 31, 2009	261,929,292	262	910,540	1,064,419	(557)	156,284	(2,427)	1,972,237	-	1,972,237

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Denbury Resources Inc.
Consolidated Statements of Changes in Stockholders' Equity
(Dollar amounts in thousands)

	Common Stock ($.001 Par Value)		Paid-In Capital in Excess of Par	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock (at cost)		Denbury Stockholders' Equity	Noncontrolling Interest	To Eq
	Shares	Amount				Shares	Amount			
Balance – December 31, 2009	261,929,292	262	910,540	1,064,419	(557)	156,284	(2,427)	1,972,237	-	1,97
Repurchase of common stock	-	-	-	-	-	413,869	(6,729)	(6,729)	-	(6,72
Issued pursuant to employee stock purchase plan	-	-	325	-	-	(491,629)	7,872	8,197	-	8,19
Issued pursuant to employee stock option plan	999,077	1	4,867	-	-	-	-	4,868	-	4,86
Issued pursuant to directors' compensation plan	16,118	-	266	-	-	-	-	266	-	266
Issued pursuant to Encore Merger	135,170,505	135	2,085,546	-	-	-	-	2,085,681	-	2,08
Encore restricted stock grants	1,070,686	1	(1)	-	-	-	-	-	-	-
Restricted stock grants	960,597	1	-	-	-	-	-	1	-	1
Restricted stock grants – forfeited	(301,735)	-	-	-	-	-	-	-	-	-
Performance-based shares issued	446,493	-	-	-	-	-	-	-	-	-
Stock-based compensation	-	-	39,791	-	-	-	-	39,791	-	39,7
Income tax benefit from equity awards	-	-	4,603	-	-	-	-	4,603	-	4,60
ENP revaluation at Encore Merger	-	-	-	-	-	-	-	-	515,210	515,
ENP cash distributions to noncontrolling interest	-	-	-	-	-	-	-	-	(36,738)	(36,
Sale of ENP	-	-	-	-	-	-	-	-	(492,193)	(492
Derivative contracts, net	-	-	-	-	69	-	-	69	(83)	(14
Consolidated net income	-	-	-	271,723	-	-	-	271,723	13,804	285,
	400,291,033	400	3,045,937	1,336,142	(488)	78,524	(1,284)	4,380,707	-	4,38

Balance –
December 31,
2010

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Denbury Resources Inc.

Consolidated Statements of Changes in Stockholders' Equity

(Dollar amounts in thousands)

	Common Stock ($.001 Par Value)		Paid-In Capital in Excess of	Retained	Accumulated Other Comprehensive Income	Treasury Stock (at cost)		Denbury Stockholders'	Noncontrolling	T
	Shares	Amount	Par	Earnings	(Loss)	Shares	Amount	Equity	Interest	E
Balance – December 31, 2010	400,291,033	400	3,045,937	1,336,142	(488)	78,524	(1,284)	4,380,707	-	4,3
Repurchase of common stock	-	-	-	-	-	14,554,016	(204,910)	(204,910)	-	(20
Issued pursuant to employee stock purchase plan	11,330	-	(1,623)	-	-	(666,867)	12,858	11,235	-	11,
Issued pursuant to employee stock option plan	1,200,759	1	4,685	-	-	-	-	4,686	-	4,6
Issued pursuant to directors' compensation plan	19,745	-	309	-	-	-	-	309	-	309
Restricted stock grants	1,134,627	1	-	-	-	-	-	1	-	1
Restricted stock grants – forfeited	(157,811)	-	-	-	-	-	-	-	-	-
Performance-based shares issued	446,387	1	-	-	-	-	-	1	-	1
Stock-based compensation	-	-	40,187	-	-	-	-	40,187	-	40,
Income tax benefit from equity awards	-	-	879	-	-	-	-	879	-	879
Derivative contracts, net	-	-	-	-	70	-	-	70	-	70
Net income	-	-	-	573,333	-	-	-	573,333	-	57
Balance – December 31, 2011	402,946,070	$403	$3,090,374	$1,909,475	$(418)	13,965,673	$(193,336)	$4,806,498	$-	$4,8

See accompanying Notes to Consolidated Financial Statements.

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Denbury Resources Inc.
Consolidated Statements of Comprehensive Operations

(In thousands)

	Year Ended December 31,		
	2011	2010	2009
Consolidated net income (loss)	$573,333	$285,527	$(75,156)
Other comprehensive income (loss), net of income tax:			
Interest rate lock derivative contracts reclassified to income, net of tax of $43, $43 and $43, respectively	70	69	70
Change in deferred hedge loss on interest rate swaps, net of tax benefit of $0, $62 and $0, respectively	-	(83)	-
Comprehensive income (loss)	573,403	285,513	(75,086)
Less: comprehensive income attributable to noncontrolling interest	-	(13,727)	-
Comprehensive income (loss) attributable to Denbury stockholders	$573,403	$271,786	$(75,086)

See accompanying Notes to Consolidated Financial Statements.

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Denbury Resources Inc.
Notes to Consolidated Financial Statements

Note 1. Significant Accounting Policies

Organization and Nature of Operations

Denbury Resources Inc., a Delaware corporation, is a growing independent oil and natural gas company. We are the largest combined oil and natural gas producer in both Mississippi and Montana, own the largest reserves of CO2 used for tertiary oil recovery east of the Mississippi River, and hold significant operating acreage in the Rocky Mountain and Gulf Coast regions. Our goal is to increase the value of our acquired properties through a combination of exploitation, drilling and proven engineering extraction practices, with our most significant emphasis on our CO2 tertiary recovery operations.

Encore Merger. On March 9, 2010, we acquired Encore Acquisition Company ("Encore"), pursuant to an Agreement and Plan of Merger (the "Encore Merger Agreement"), under which Encore was merged with and into Denbury (the "Encore Merger"), with Denbury surviving the Encore Merger following approval by the stockholders of both Denbury and Encore, closing of a new revolving credit facility as part of the financing for the Encore Merger, and satisfaction of conditions precedent. The Encore Merger provided Encore stockholders stock and/or cash and included the assumption of Encore's debt by Denbury. Denbury has consolidated Encore's results of operations since March 9, 2010, the acquisition date. See Note 2, Acquisitions and Divestitures, for more information.

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. Investments in non-controlled entities over which we exercise significant influence are accounted for under the equity method. Other investments are carried at cost. All intercompany balances and transactions have been eliminated.

From March 9, 2010 through December 31, 2010, we owned approximately 46% of Encore Energy Partners LP ("ENP") outstanding common units and 100% of Encore Energy Partners GP LLC ("GP LLC"), which was ENP's general partner. Considering the presumption of control of GP LLC in accordance with the Consolidation topic of the Financial Accounting Standards Board Codification ("FASC"), the results of operations and cash flows of ENP were consolidated with those of Denbury for this period. On December 31, 2010, we sold all of our ownership interests in ENP and GP LLC and, therefore, we did not consolidate ENP in our Consolidated Balance Sheet as of December 31, 2010. As presented in the accompanying Consolidated Statement of Operations for the year ended December 31, 2010, "Net income attributable to noncontrolling interest" of $13.8 million represents ENP's results of operations attributable to limited partners other than Denbury for the portion of the year for which we consolidated ENP.

At December 31, 2009, we owned the general partner of Genesis Energy, L.P. ("Genesis"), a publicly-traded master limited partnership, and approximately 10% of Genesis' outstanding common units. In aggregate, our ownership interests represented approximately a 12% ownership interest in Genesis, which we accounted for under the equity method of accounting. On February 5, 2010, we sold our general partner interest in Genesis, and in March 2010 we sold our Genesis common units. See Note 2, Acquisitions and Divestitures, for more information.

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 and 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) accruals related to oil and natural gas sales volumes and revenues, capital expenditures and lease operating expenses, (4) the estimated costs and timing of future asset retirement obligations, (5) estimates made in the calculation of income taxes, and (6) 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.

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Denbury Resources Inc.
Notes to Consolidated Financial Statements

Reclassifications

Certain prior period amounts have been reclassified to conform with the current year presentation. On the Consolidated Statements of Operations for the years ended December 31, 2010 and 2009, "Taxes other than income" is a new line item and includes oil and natural gas ad valorem taxes, which were reclassified from "Lease operating expenses," franchise taxes and property taxes on buildings, which were reclassified from "General and administrative expenses," oil and natural gas production taxes, which were reclassified from "Production taxes and marketing expenses" used in prior reports and CO2 property ad valorem and production taxes, which were classified from "CO2 discovery and operating expense." On the Consolidated Balance Sheet as of December 31, 2010, "Pipelines and plants" was reclassified from "CO2 and other products – properties and pipelines" used in prior reports, helium properties were reclassified to "Other property and equipment" from "CO2 and other products - properties and pipelines" used in prior reports, and "Other current assets" was reclassified from "Trade and other receivables, net." Such reclassifications had no impact on our reported total expenses, net income, current assets, total assets, current liabilities, total liabilities or stockholders' equity.

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.

Short-term Investments

Short-term investments are available-for-sale securities recorded at fair value with any unrealized gains or losses included in accumulated other comprehensive income. At December 31, 2011 and 2010, short-term investments consisted entirely of our investment in Vanguard Natural Resources LLC ("Vanguard") common units obtained as partial consideration for the sale of our interests in ENP to a subsidiary of Vanguard on December 31, 2010. See Note 2, Acquisitions and Divestitures. Our original cost basis of this investment was $93.0 million. We received distributions of $7.2 million on the Vanguard common units we own for the year ended December 31, 2011, which are included in "Interest income and other income" on our Consolidated Statements of Operations. Due to the decline in the market value of this investment and the expectation that the investment would not recover to its cost basis prior to the time of sale, we recorded a $6.3 million "other-than-temporary" impairment loss on this investment for the year ended December 31, 2011, which is included in "Impairment of assets" on our Consolidated Statements of Operations. This investment was sold in January 2012 for cash consideration of $83.5 million, net of related transaction fees. See Note 14, Subsequent Events.

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 acquisitions, 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 non-productive 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 FASC Fair Value Measurements and Disclosures 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.

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. The depletion and depreciation rate per BOE associated with our oil and gas producing activities was $16.42 in 2011, $15.82 in 2010 and $13.39 in 2009.

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 the sum of (1) the present value of estimated future net revenues from proved reserves before future abandonment costs (discounted at −−10%), based on unescalated period-end oil and natural gas prices during the first three quarters of 2009; and beginning in the fourth quarter of 2009, the average first-day-of-the-month oil and natural gas price for each month during the 12-month period prior to the end of a particular reporting period; (2) plus the cost of properties not being amortized; (3) plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; (4) less 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 CO2 reserves nor those related to the cost of constructing CO2 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 the Company’s capitalized CO2 costs related to CO2 reserves and CO2 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, 2011, 2010 or 2009.

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Denbury Resources Inc.
Notes to Consolidated Financial Statements

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 Denbury's 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 CO2 injection, until there is a production response to the injected CO2, or unless the field is analogous to an existing flood. Our costs associated with the CO2 we produce and inject are principally our costs of production, transportation and acquisition, and payment of 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 CO2 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 CO2 injections (i.e., the production stage), injection costs are expensed as incurred, and once proved reserves are recognized, previously deferred unevaluated development costs will become subject to depletion.

CO2 Properties

We own and produce CO2 reserves, a non-hydrocarbon resource, that are used in our tertiary oil recovery operations on our own behalf and on behalf of other working interest owners in our enhanced recovery fields, with a portion sold to third-party industrial users. We record revenue from our sales of CO2 to third parties when it is produced and sold. Expenses related to the production of CO2 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 "CO2 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 status of floods that receive the CO2 (see Tertiary Injection Cost above for further discussion).

During 2010 and 2011, we acquired interests in the Riley Ridge Federal Unit ("Riley Ridge"), in which helium, a non-hydrocarbon resource, as well as natural gas, a hydrocarbon, are present. It is not possible to separately identify the capitalized costs related to the development of each product in the comingled gas stream; thus, these costs are allocated between "Oil and natural gas properties", "CO2 properties" and "Other property and equipment" on the Consolidated Balance Sheets based on the relative future revenue value of each product line.

During 2010, we revised our capitalization policies for CO2 properties. Previously, we accounted for our CO2 source properties in a manner similar to our method of accounting for oil and natural gas properties, as the process and activities to identify, develop and produce CO2 reserves are virtually identical to those used to identify, develop and produce oil and natural gas reserves. However, because CO2 is not a hydrocarbon, it is excluded from the scope of FASC Topic 932, Extractive Industries – Oil and Gas, and, therefore, we are precluded from accounting for our CO2 operations in accordance with FASC Topic 932. Accordingly, commencing in July 2010, costs incurred to search for CO2 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 "CO2 properties" on our Consolidated Balance Sheets. Capitalized CO2 is aggregated by geologic formation and depleted on a unit-of-production basis over proved and probable reserves. The impact of the revised accounting policy on our financial statements was not material to any individual year. The Company recognized the cumulative impact of the revised accounting policy as a non-cash net reduction to depletion, depreciation and amortization during the year ended December 31, 2010, resulting in a pretax credit of $9.6 million ($6.0 million after tax), which reflected a reduction to "CO2 properties" of $26.1 million offset by a decrease in "Accumulated depletion, depreciation and amortization" of $35.7 million. The cumulative adjustment did not have an impact on our net cash flows.

The portion of the Company's capitalized CO2 costs related to CO2 reserves and CO2 pipelines that we estimate will be consumed in the process of producing our proved oil reserves is included in the ceiling test as a reduction to future net revenues. The remaining net capitalized CO2 properties, equipment and pipelines balance is evaluated for impairment by comparing the net carrying costs to the expected future net revenues from (1) the production of our probable and possible tertiary oil reserves and (2) the sale of CO2 to third-party industrial users.

Pipelines and Plants

CO2 used in our tertiary floods is transported to our fields through CO2 pipelines. Costs of CO2 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 plant in southwestern Wyoming, which is currently under construction. The plant is being withheld from depreciation until it is placed in service, which we currently expect to occur during the second quarter of 2012.

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 estimated useful lives. 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 lives of property and equipment are charged to expense as incurred.

Asset Retirement Obligations

In general, our future asset retirement obligations relate to future costs associated with plugging and abandonment of our oil, natural gas and CO2 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 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 and are discounted using the Company’s credit-adjusted-risk-free rate. We utilize unobservable inputs in the estimation of asset retirement obligations that include, but are not limited to, costs of labor, costs of 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 Measurements and Disclosures topic.

Derivative Instruments and Hedging Activities

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 or collars, and fixed price swaps. From time to time, we have also used interest rate lock contracts to mitigate our exposure to interest rate fluctuations related to sale-leaseback financing of certain equipment used at our oilfield facilities. 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 oil and natural gas derivative contracts; accordingly, the changes in the fair value of these instruments are recognized in our Consolidated Statements of Operations in the period of change.

Financial Instruments with Off-Balance-Sheet Risk and 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 banks, which are part of the syndicate of banks in our bank credit facility, or with their affiliates. There are no margin requirements with the counterparties of our derivative contracts.

Goodwill

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 fair value of a reporting unit with goodwill has been reduced below 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 book 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 book 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 book value, the recorded goodwill is impaired to its implied fair value with a charge to operating expense. We completed our annual goodwill impairment assessment during the fourth quarter of 2011 and did not record any goodwill impairment during 2011, nor have we recorded a goodwill impairment historically.

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Denbury Resources Inc.
Notes to Consolidated Financial Statements

The following table summarizes the changes in goodwill for the years ended December 31, 2011 and 2010:

In thousands	2011	2010
Beginning of year balance	$1,232,418	$169,517
Adjustment to goodwill related to the acquisition of interests in the Conroe Field	-	318
Goodwill related to the Encore Merger	-	1,061,123
Goodwill related to the Riley Ridge acquisition	3,900	1,460
End of year balance	$1,236,318	$1,232,418

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 all 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, 2011 and 2010, 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 either the closing or purchase agreement date, depending on the underlying terms and agreements.

Income Taxes

Income taxes are accounted for using the 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 also considers the impact to net income and common shares of the potential dilution from stock options, stock appreciation rights (“SARs”), non-vested restricted stock and non-vested performance equity awards.

For each of the three years in the period ended December 31, 2011, 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	2011	2010	2009
Basic weighted average common shares	396,023	370,876	246,917
Potentially dilutive securities:			
Stock options and SARs	3,539	3,844	-
Performance equity awards	38	319	-
Restricted stock	1,358	1,216	-
Diluted weighted average common shares	400,958	376,255	246,917

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Denbury Resources Inc.
Notes to Consolidated Financial Statements

Basic weighted average common shares excludes 3.4 million, 3.2 million and 2.5 million shares of non-vested restricted stock during the year ended December 31, 2011, 2010 and 2009, respectively. As these restricted shares vest or become retirement eligible, they will be included in the shares outstanding used to calculate basic net income per common share (although all restricted stock is issued and outstanding upon grant). For purposes of calculating diluted weighted average common shares, the non-vested restricted stock is included in the computation using the treasury stock method, with the deemed proceeds equal to the average unrecognized compensation during the period, adjusted for any estimated future tax consequences recognized directly in equity.

The following securities could potentially dilute earnings per share in the future but were not included in the computation of diluted net income per share, as their effect would have been anti-dilutive:

	Year Ended December 31,		
In thousands	2011	2010	2009
Stock options and SARs	5,017	3,671	10,764
Performance equity awards	-	-	523
Restricted stock	104	17	2,507
Total	5,121	3,688	13,794

Recently Adopted Accounting Pronouncements

Goodwill. In September 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2011-08, Testing Goodwill for Impairment, ("ASU 2011-08"). ASU 2011-08 amends the FASC Intangibles – Goodwill and Other topic by permitting entities to assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test described in the FASC Intangibles – Goodwill and Other topic. We adopted ASU 2011-08 in 2011.

Recently Issued Accounting Pronouncements

Balance Sheet Offsetting. In December 2011, the FASB issued ASU 2011-11, Disclosure about Offsetting Assets and Liabilities ("ASU 2011-11"). ASU 2011-11 requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. ASU 2011-11 will be effective for our fiscal year beginning January 1, 2013 and will be applied retrospectively for all comparative periods presented. The adoption of ASU 2011-11 is not expected to have a material effect on our consolidated financial statements, but may require additional disclosures.

Comprehensive Income. In June 2011, the FASB issued ASU 2011-05, Presentation of Comprehensive Income, ("ASU 2011-05"). ASU 2011-05 requires the presentation of comprehensive income in either 1) a continuous statement of comprehensive income or 2) two separate but consecutive statements. In December 2011, the FASB issued ASU 2011-12, which defers certain requirements within ASU 2011-05. These amendments are being made to allow the FASB time to redeliberate whether to present on the face of the financial statements the effects of reclassifications out of accumulated other comprehensive income on the components of net income and other comprehensive income in all periods presented. ASU 2011-05 and the amendments in ASU 2011-12 will be effective for our fiscal year beginning January 1, 2012. Since the ASUs will only amend presentation requirements, they are not expected to have a material effect on our consolidated financial statements.

Fair Value. In May 2011, the FASB issued ASU 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs, ("ASU 2011-04"). ASU 2011-04 amends the FASC Fair Value Measurements topic by providing a consistent definition and measurement of fair value, as well as similar disclosure requirements between U.S. GAAP and International Financial Reporting Standards. ASU 2011-04 changes certain fair value measurement principles, clarifies the application of existing fair value measurements and expands the fair value disclosure requirements, particularly for Level 3 fair value measurements. ASU 2011-04 will be effective for our fiscal year beginning January 1, 2012. The adoption of ASU 2011-04 will not have a material effect on our consolidated financial statements but may require additional disclosures.

Note 2. Acquisitions and Divestitures

Acquisitions

Fair Value. The FASC Fair Value Measurements and Disclosures 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.

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The fair value of oil and natural gas properties is based on significant inputs not observable in the market, which the FASC Fair Value Measurements and Disclosures topic defines as Level 3 inputs. Key assumptions include (1) NYMEX oil and natural gas futures (this input is observable), (2) projections of the estimated quantities of oil and natural gas reserves, including those classified as proved, probable, and possible, (3) projections of future rates of production, (4) timing and amount of future development and operating costs, (5) projected cost of CO2 (to a market participant), (6) projected reserve recovery factors, and (7) risk-adjusted discount rates. Fair value is determined using a risk-adjusted after-tax discounted cash flow analysis.

October 2010 and August 2011 Riley Ridge Acquisitions. In October 2010, we acquired a 42.5% non-operated working interest in Riley Ridge, located in southwestern Wyoming, for $132.3 million after closing adjustments. Riley Ridge contains natural gas resources, as well as helium and CO2 resources. The purchase includes a 42.5% interest in a gas plant, currently under construction, which will separate the helium and natural gas from the comingled gas stream, and interests in certain surrounding properties. The fair values assigned to assets acquired and liabilities assumed in the October 2010 acquisition have been finalized, and no adjustments have been made to amounts previously disclosed in our Form 10-K for the year ended December 31, 2010.

On August 1, 2011, we acquired the remaining 57.5% working interest in Riley Ridge we did not already own, the remaining 57.5% interest in the gas plant, and interests in certain surrounding properties. As a result of the transaction, we became the operator of both projects. The purchase price was approximately $214.8 million after closing adjustments, including a $15 million deferred payment to be made at the time the property's gas plant is operational and meets specific performance conditions. We currently expect the gas plant to be operational during the second quarter of 2012.

Because the Riley Ridge plant remains under construction, current production at the field is negligible. As a result, pro forma information has not been disclosed due to the immateriality of revenues and expenses during 2011 and 2010.

The acquisition of Riley Ridge meets the definition of a business under the FASC Business Combinations topic. Goodwill associated with the acquisition is deductible for income tax purposes. The following table presents a summary of the preliminary fair value of assets acquired:

In thousands		
Consideration:		
Cash payment	$	199,779
Deferred payment(1)		15,000
Total consideration		214,779
Less: Fair value of assets acquired and liabilities assumed:		
Oil and natural gas properties		
Proved		48,731
Unproved		12,542
CO2 properties		9,741
Pipelines and plants		91,594
Other assets(2)		48,660
Asset retirement obligations		(389)

		210,879
Goodwill	$	3,900

(1) The deferred payment is included in "Accounts payable and accrued liabilities" on the accompanying balance sheet and will be paid at the time the property's gas plant is operational and meets specific performance conditions as described above.

(2) Other assets includes helium extraction rights of $36.7 million. Helium reserves at Riley Ridge are owned by the U.S. Government. The fair value assigned to helium extraction rights was calculated using the income approach and represents the discounted future net revenues associated with the Company's right to extract and sell the helium on behalf of the helium resource owners. Upon commencement of helium production, helium extraction rights will be amortized on a units-of-production basis.

2010 Merger with Encore Acquisition Company. On March 9, 2010, we acquired Encore pursuant to the Encore Merger Agreement entered into with Encore on October 31, 2009. The Encore Merger Agreement provided for a stock and cash transaction valued at approximately $4.8 billion at the acquisition date, including the assumption of debt and the value of the noncontrolling interest in ENP. Under the Encore Merger Agreement, Encore was merged with and into Denbury, with Denbury surviving the Encore Merger.

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In the Encore Merger, we issued approximately 135.2 million shares of common stock and paid approximately $833.9 million in cash to Encore stockholders. The Denbury shares issued to Encore stockholders represented approximately 34% of Denbury's common stock issued and outstanding immediately after the Encore Merger. The total fair value of our common stock issued to Encore stockholders in the Encore Merger was approximately $2.1 billion based upon our closing price of $15.43 per share on March 9, 2010.

The Encore Merger was financed through a combination of issuing $1.0 billion of 8¼% Senior Subordinated Notes due 2020 (the "2020 Notes"), which we issued on February 10, 2010, borrowings under a new $1.6 billion revolving credit agreement (the "Credit Agreement") entered into on March 9, 2010, and the assumption of Encore's remaining outstanding senior subordinated notes.

The Encore Merger met the definition of a business combination under the FASC Business Combinations topic. As such, we estimated the fair value of Encore as of the acquisition date, which is the date on which we obtained control of Encore. The acquisition date for the Encore Merger was March 9, 2010.

In applying these accounting principles, we estimated the fair value of the Encore assets acquired less liabilities assumed on the acquisition date to be approximately $2.4 billion. This measurement resulted in the recognition of goodwill totaling approximately $1.1 billion. Goodwill was calculated as the excess of the consideration transferred to acquire Encore plus the fair value of the noncontrolling interest in ENP, over the acquisition date estimated fair value of the net assets acquired. Goodwill recorded in the Encore Merger primarily represents the value of the opportunity to expand Encore's CO_2 EOR operations in the Rocky Mountain region, the experience and technical expertise of former Encore employees who have joined Denbury, and the addition of strategic areas of operations in which we did not previously have a significant presence. None of the goodwill is deductible for income tax purposes.

The following table is a summary of the consideration issued in the Encore Merger and the fair value of the assets acquired and liabilities assumed at the acquisition date, as well as the fair value at the acquisition date of the noncontrolling interest in ENP.

In thousands

Consideration and noncontrolling interest:			
	Fair value of Denbury common stock issued (1)	$	2,085,681
	Cash payment to Encore stockholders (2)		833,909
	Severance payments		32,925
	Consideration issued		2,952,515
	Fair value of noncontrolling interest of ENP (3)		515,210
	Consideration and noncontrolling interest of ENP (4)		3,467,725
Add: fair value of liabilities assumed:			
	Accounts payable and accrued liabilities		116,236
	Oil and natural gas production payable		54,201
	Current derivatives		65,954
	Other current liabilities		38,407
	Long-term debt		1,375,149
	Asset retirement obligations		42,360
	Long-term derivatives		35,631
	Long-term deferred taxes		871,912
	Other long-term liabilities		2,717
Amount attributable to liabilities assumed			2,602,567

Less: fair value of assets acquired:			
	Cash and cash equivalents		51,850
	Accrued production receivable		124,494
	Trade and other receivables		43,643
	Current derivatives		29,737
	Other current assets		2,740
	Oil and natural gas properties – proved		3,340,141
	Oil and natural gas properties – unevaluated		1,279,000
	Pipelines and plants		7,254
	Other property, plant and equipment		11,475
	Long-term derivatives		35,207
	Other long-term assets		83,628
Amount attributable to assets acquired			5,009,169
Goodwill		$	1,061,123

(1) 135.2 million Denbury common shares at $15.43 per share.

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(2) Based on cash paid to holders of Encore issued and outstanding common stock who elected to receive all cash or who received a combination of cash and stock; also includes cash payment to stock option holders of $4.5 million.

(3) Represents fair value of the noncontrolling interest of ENP. As of March 9, 2010, there were 45.3 million ENP common units outstanding, and the closing price was $21.10 per common unit. As of March 9, 2010, Encore owned approximately 46% of ENP's outstanding units.

(4) The sum of the consideration issued, the noncontrolling interest of ENP and the fair value of Encore's long-term debt assumed totals approximately $4.8 billion, representing the aggregate purchase price.

For the period from March 9, 2010 to December 31, 2010, we recognized $623.4 million of oil, natural gas and related product sales related to properties acquired in the Encore Merger. For the period from March 9, 2010, to December 31, 2010, we recognized $426.0 million net field operating income (oil, natural gas and related product sales less lease operating expenses and production taxes and marketing expenses) related to properties acquired in the Encore Merger. Transaction and other costs related to the Encore Merger included in the Consolidated Statement of Operations for the year ended December 31, 2010, include $48.5 million of third-party, legal and accounting fees, which have been expensed as incurred, and $43.8 million of employee-related severance and termination costs, which are accrued over the employees' service period. Accrued employee-related severance costs totaled $19.8 million at December 31, 2010, of which $16.5 million was classified as Accounts payable and accrued liabilities, and $3.3 million was classified as long-term Other liabilities on our balance sheet. Transaction and other costs related to the Encore Merger included in the Consolidated Statement of Operations for the year ended December 31, 2011, include $0.8 million of third-party, legal and accounting fees, which have been expensed as incurred, and $3.6 million of employee-related severance and termination costs.

2010 Unaudited Pro Forma Acquisition Information. Had our acquisition of Encore occurred on January 1, 2010, our combined pro forma revenue and net income (loss) would have been as follows:

	Year Ended December 31,	
In thousands	2010	2009
Pro forma total revenues and other income	$2,098,241	$1,568,050
Pro forma net income (loss) attributable to Denbury stockholders	286,891	(137,227)
Pro forma net income (loss) per common share:		
Basic	0.73	(0.35)
Diluted	0.72	(0.35)

Dispositions

2010 Sale of Interests in Genesis. In February 2010, we sold our interest in Genesis Energy, LLC, the general partner of Genesis, for net proceeds of approximately $84 million, after giving effect to the change of control provision of the incentive compensation agreement with Genesis' management, which was triggered and under which we paid a total of $14.9 million. In March 2010, we sold all of our Genesis common units in a secondary public offering for net proceeds of approximately $79 million. We recognized a pre-tax gain of approximately $101.5 million ($63.0 million after tax) on these dispositions.

2010 Sales of Non-strategic Encore Legacy Properties. Pursuant to our plan of divesting non-strategic legacy Encore properties, certain oil and gas properties in the Permian Basin, Mid-continent area and East Texas Basin were sold in

May 2010 for consideration of $892.1 million after final closing adjustments. We subsequently divested our production and acreage in the Cleveland Sand Play of western Oklahoma for consideration of $32.1 million after closing adjustments, and the Haynesville and East Texas natural gas properties for consideration of $213.8 million after closing adjustments. In addition to the property sales, we sold our ownership interests in ENP and GP LLC on December 31, 2010. Collectively, we received $1.5 billion in total consideration from these divestitures in 2010. For all Encore legacy property dispositions during 2010, we reduced our full cost pool by the amount of the net proceeds and did not record a gain or loss on the sale in accordance with the full cost method of accounting.

2010 Sale of Ownership Interests in ENP. In December 2010, we sold our ownership interests in ENP, which consisted of our 100% ownership in GP LLC, ENP's general partner, and 20.9 million ENP common units, to a subsidiary of Vanguard for consideration consisting of $300.0 million cash and 3,137,255 Vanguard common units valued at $93.0 million at the time of closing. In addition, Vanguard assumed all of ENP's long-term bank debt of $234.0 million. We have classified the units as available-for-sale securities in "Short-term investments" on the Consolidated Balance Sheets. We did not record a gain or loss on the sale of oil and gas properties in accordance with the full cost method of accounting, nor did we record a gain or loss on the remainder of the net assets sold as the book value approximated fair value.

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Note 3. Asset Retirement Obligations

The following table summarizes the changes in our asset retirement obligations for the years ended December 31, 2011 and 2010:

	Year Ended December 31,	
In thousands	2011	2010
Beginning asset retirement obligation	$ 85,744	$ 54,338
Liabilities incurred and assumed during period	12,477	4,291
Liabilities assumed in the Encore Merger	-	43,783
Revisions in estimated retirement obligations	12,217	5,505
Liabilities settled during period	(23,225)	(6,622)
Accretion expense	6,287	6,443
Sales of properties	(32)	(21,994)
Ending asset retirement obligation	93,468	85,744
Less: current asset retirement obligation(1)	(4,742)	(4,454)
Long-term asset retirement obligation	$ 88,726	$ 81,290

(1) Included in "Accounts payable and accrued liabilities" in our Consolidated Balance Sheets

Liabilities incurred and assumed are primarily related to the drilling of incremental wells, during 2011 to the plugging of old wells in the Tinsley Field, and during 2010 to the Encore Merger. Sales of properties during 2010 are primarily related to the disposition of our non-strategic legacy Encore properties and our interests in ENP. The reversal of these asset retirement obligations, which were assumed by the purchasers, was recorded as an adjustment to the full cost pool with no gain or loss recognized, in accordance with the full cost method of accounting.

We have escrow accounts that are legally restricted for certain of our asset retirement obligations. The balances of these escrow accounts were $34.1 million and $33.1 million at December 31, 2011 and 2010, respectively. These balances are recorded at amortized cost and are included in “Other assets” in our Consolidated Balance Sheets. The estimated fair market value of these investments at December 31, 2011 and 2010 approximate cost.

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Note 4. Property and Equipment

The following table presents a summary of our net property and equipment balances as of December 31, 2011 and 2010:

In thousands	December 31, 2011	2010
Oil and natural gas properties		
Proved properties	$ 7,026,579	$ 6,042,442
Unevaluated properties	1,157,106	870,130
Total	8,183,685	6,912,572
Accumulated depletion and depreciation	(2,407,520)	(2,045,091)
Net oil and natural gas properties	5,776,165	4,867,481
CO_2 properties		
CO_2 properties	596,003	522,091
Accumulated depletion and depreciation	(91,666)	(68,479)
Net CO_2 properties	504,337	453,612
Pipelines and plants		
CO_2 pipelines in service	1,277,326	1,240,710
CO_2 pipelines under construction(1)	155,320	53,922
Plants under construction(1)	269,110	83,607
Total	1,701,756	1,378,239
Accumulated depletion and depreciation	(65,392)	(31,866)
Net plants and pipelines	1,636,364	1,346,373
Other property and equipment		
Other property and equipment	157,674	121,973
Accumulated depletion and depreciation	(62,915)	(52,081)
Net other property and equipment	94,759	69,892
Net property and equipment	$ 8,011,625	$ 6,737,358

(1) Amounts primarily include the Greencore pipeline in southwestern Wyoming, which is expected to be completed in late 2012, and the Riley Ridge gas plant, which is currently expected to be placed in service in the second quarter of 2012. Amounts are excluded from DD&A expense until placed into service.

A summary of the unevaluated properties excluded from oil and natural gas properties being amortized at December 31, 2011, and the year in which they were incurred follows:

	December 31, 2011 Costs Incurred During:				
In thousands	2011	2010	2009	2008 and prior	Total
Property acquisition costs	$12,543	$560,314	$94,969	$49,566	$717,392

Exploration and development	270,062	86,251	3,758	6,682	366,753
Capitalized interest	44,853	20,958	3,228	3,922	72,961
Total	$327,458	$667,523	$101,955	$60,170	$1,157,106

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, 2011. The most significant of these costs during 2011 related to Oyster Bayou and Hastings Fields, for which we have initiated CO2 floods but have not yet recognized proved reserves. Our 2010 property acquisition costs were primarily related to the fair value allocated to CO2 tertiary potential at our Bell Creek and Cedar Creek Anticline properties and the undeveloped potential assigned to our Bakken properties, all acquired as part of the Encore Merger. Our 2009 property acquisition costs were primarily related to CO2 tertiary potential at our Conroe Field. Property acquisition costs for 2008 and prior were primarily for CO2 tertiary potential at Oyster Bayou.

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During 2011, we established proved reserves in the Williston and Bakken areas, and as a result we transferred $51.2 million of costs incurred on this project into the amortization base. 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 most of these properties and the inclusion of their costs in the amortization base is expected to be completed within five 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, 2011 and 2010:

	December 31,	
In thousands	2011	2010
Bank Credit Agreement	$ 385,000	$ -
7½% Senior Subordinated Notes due 2013, including discount of $437	-	224,563
7½% Senior Subordinated Notes due 2015, including premium of $427	-	300,427
9½% Senior Subordinated Notes due 2016, including premium of $11,854 and $14,589, respectively	236,774	239,509
9¾% Senior Subordinated Notes due 2016, including discount of $17,854 and $22,139, respectively	408,496	404,211
8¼% Senior Subordinated Notes due 2020	996,273	996,273
6 % Senior Subordinated Notes due 2021	400,000	-
Other Subordinated Notes, including premium of $33 and $41, respectively	3,840	3,848
NEJD financing	163,677	167,331
Free State financing	79,597	81,188
Capital lease obligations	4,388	6,806
Total	2,678,045	2,424,156
Less: current obligations	(8,316)	(7,948)
Long-term debt and capital lease obligations	$ 2,669,729	$ 2,416,208

The parent company, 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 is 100% owned by DRI; any subsidiaries of DRI other than the subsidiary guarantors are minor subsidiaries, and the guarantees are full and unconditional and joint and several.

$1.6 Billion Revolving Credit Agreement

In March 2010, we entered into a $1.6 billion revolving credit agreement with JPMorgan Chase Bank, N.A. (“JPMorgan”), as administrative agent, and other lenders as party thereto (the “Bank Credit Agreement”). Availability under the Bank Credit Agreement is subject to a borrowing base, which is redetermined semi-annually on or prior to May 1 and November 1 and upon requested special redeterminations. The borrowing base is adjusted at the banks’ discretion and is based in part upon external factors over which we have no control. If the borrowing base were to be less than outstanding borrowings under the Bank Credit Agreement, we would be required to repay the deficit over a period not to exceed four months. As part of the semi-annual review completed in September 2011 pursuant to the terms of the Bank Credit Agreement, our borrowing base was reaffirmed at $1.6 billion. Loans under the Bank Credit Agreement mature in May 2016.

The Bank Credit Agreement is secured by substantially all of the proved oil and natural gas properties of our restricted subsidiaries and by the equity interests of our restricted subsidiaries. In addition, our obligations under the Bank Credit Agreement are guaranteed jointly and severally by all of our subsidiaries, other than minor subsidiaries.

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

- a limitation on the ability to repurchase Denbury common stock and to pay dividends on Denbury common stock, in an aggregate amount not to exceed $500 million during the term of the Bank Credit Agreement, subject to certain restrictions;
- a requirement to maintain a current ratio, as determined under the Bank Credit Agreement, of not less than 1.0 to 1.0;
- a maximum permitted ratio of debt to adjusted EBITDA (as defined in the Bank Credit Agreement) of us and our restricted subsidiaries of not more than 4.25 to 1.0; and
- a prohibition against incurring debt, subject to permitted exceptions.

The Bank Credit Agreement also includes a limitation on the aggregate amount of forecasted oil and natural gas production that can be economically hedged with oil or natural gas derivative contracts.

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Loans under the Bank Credit Agreement are subject to varying rates of interest based on (1) the total outstanding borrowings in relation to the borrowing base and (2) whether the loan is a Eurodollar loan or a base rate loan. Eurodollar loans bear interest at the Adjusted Eurodollar Rate (as defined in the Bank Credit Agreement) plus the applicable margin of 1.5% to 2.5% based on the ratio of outstanding borrowings to the borrowing base, and base rate loans bear interest at the Base Rate (as defined in the Bank Credit Agreement) plus the applicable margin of 0.5% to 1.5% based on the ratio of outstanding borrowings to the borrowing base. The "Eurodollar rate" for any interest period (either one, two, three, six, nine or twelve months, as selected by us) is the rate per year equal to LIBOR, as published by Reuters or another source designated by JPMorgan, for deposits in dollars for a similar interest period. The "base rate" is calculated as the highest of (1) the annual rate of interest announced by JPMorgan as its "prime rate," (2) the federal funds effective rate plus 0.5%, and (3) the Adjusted Eurodollar Rate for a one-month interest period plus 1.0%. We incur a commitment fee of either 0.375% or 0.5%, based on the ratio of outstanding borrowings on the borrowing base, on the unused portion of the credit facility or, if less, the borrowing base.

7½% Senior Subordinated Notes due 2013 and 7½% Senior Subordinated Notes due 2015

In March 2003, we issued $225 million of 7½% Senior Subordinated Notes due 2013 ("2013 Notes"). The 2013 Notes, which carried a coupon rate of 7.5%, were sold at 99.135% of par. In December 2005, we issued $150 million of 7½% Senior Subordinated Notes due 2015, which carried a coupon rate of 7.5%, at par. In April 2007, we issued an additional $150 million of 7½% Senior Subordinated Notes due 2015 (collectively the "2015 Notes") at 100.5% of par, equating to an effective yield to maturity of approximately 7.4%. On March 3, 2011, we purchased in a tender offer $169.6 million in principal of the 2013 Notes at 100.625% of par, and $220.9 million in principal of the 2015 Notes at 104.125% of par. We called the remaining 2013 and 2015 Notes, repurchasing all of the remaining outstanding 2015 Notes ($79.1 million) at 103.75% of par on March 21, 2011, and all of the remaining outstanding 2013 Notes ($55.4 million) at par on April 1, 2011. We recognized a $16.1 million loss during the year ended December 31, 2011 associated with the debt repurchases, which is included in our Unaudited Condensed Consolidated Statements of Operations under the caption "Loss on early extinguishment of debt".

Supplements to Indentures Governing Encore's Senior Subordinated Notes

On March 9, 2010, upon closing of the Encore Merger, we became an obligor, as successor in interest to Encore, with respect to Encore's senior subordinated notes, which are governed by four indentures covering an aggregate original principal amount of $825 million. In conjunction with the closing of the Encore Merger, we and our subsidiaries other than minor subsidiaries entered into supplemental indentures to become subsidiary guarantors under Encore's senior subordinated notes, as required under the Encore indentures, as well as the indentures governing our senior subordinated notes. The Encore legacy subsidiaries, with permitted exceptions, became guarantors under the indentures that were in effect prior to the Encore Merger.

Tender Offers and Consent Solicitations for Encore's Senior Subordinated Notes; Supplements to Indentures Governing Encore's Senior Subordinated Notes

On March 10, 2010, we purchased in a cash tender offer $500.5 million of $600 million principal amount of Encore's senior subordinated notes that were governed by three of Encore's four indentures, leaving approximately $99.5 million of the $600 million of notes outstanding. Those indentures to which Encore was a party prior to the Encore Merger govern their 6¼% Senior Subordinated Notes due 2014, their 6% Senior Subordinated Notes due 2015 and their 7¼% Senior Subordinated Notes due 2017 (collectively, the "Other Subordinated Notes").

The tender of the notes also constituted the delivery of consents of holders of the notes to eliminate or modify certain provisions contained in each of the three indentures governing the Other Subordinated Notes, which was sufficient to amend these three Encore indentures effective upon the date of the Encore Merger. The amendments of the three indentures governing the $600 million of Other Subordinated Notes eliminated most of the restrictive covenants and certain events of default in the indentures. The amendments do not apply to the 9½% Senior Subordinated Notes due 2016 (the "9½% Notes"). The Encore indentures required us to effect a second tender offer to repurchase, for 101% of the face amount, the $99.5 million of notes that remained outstanding after completion of the February 8, 2010 tender, plus an initial offer to purchase, for 101% of the face amount, the $225 million of outstanding 9½% Notes. In April 2010, we purchased approximately $95.7 million of these senior subordinated notes, leaving approximately $228.7 million of former Encore notes outstanding.

Encore Indentures

In addition to the three indentures that govern the Other Subordinated Notes, as a result of the Encore Merger, we also became successor in interest to Encore under the Encore indenture with respect to the 9½% Notes in the original principal amount of $225 million. Interest on the 9½% Notes is due semi-annually, on May 1 and November 1, at a rate of 9.5%. The 9½% Notes mature on May 1, 2016. We may redeem the 9½% Notes, in whole or in part at our option beginning May 1, 2013, at the following redemption prices: 104.75% after May 1, 2013, 102.375% after May 1, 2014 and 100% after May 1, 2015. Prior to May 1, 2012, we may, at our option, redeem up to an aggregate of 35% of the principal amount of the 9½% Notes at a price of 109.5% with the proceeds of certain equity offerings. In addition, at any time prior to May 1, 2013, we may redeem 100% of the principal amount of the 9½% Notes at a price equal to 100% of the principal amount plus a "make-whole" premium and accrued and unpaid interest. The material terms of the indenture governing the 9½% Notes include covenants requiring the filing of SEC reports, restricting certain payments, limiting indebtedness, restricting distributions from certain restricted subsidiaries, restricting affiliate transactions, restricting the creation of liens, requiring certain subsidiaries to deliver guarantees of the notes, requiring the delivery of certificates concerning compliance with the indenture, and covenants relating to mergers and consolidations.

All of the Encore indentures, including the indenture governing the 9½% Notes, have covenants limiting the sale of assets and providing a put right by holders upon a change of control, as well as other certain affirmative and negative covenants.

9¾% Senior Subordinated Notes due 2016

In February 2009, we issued $420 million of 9¾% Senior Subordinated Notes due 2016 (“2016 Notes”). The 2016 Notes, which carry a coupon rate of 9.75%, were sold at a discount (92.816% of par), which equates to an effective yield to maturity of approximately 11.25%.

In June 2009, we issued an additional $6.35 million of 2016 Notes to our founder, Gareth Roberts, as part of a Founder’s Retirement Agreement. In connection with this issuance, we recorded compensation expense of $6.35 million in “General and administrative” expense in our Consolidated Statement of Operations during the year ended December 31, 2009.

The 2016 Notes mature on March 1, 2016, and interest on the 2016 Notes is payable March 1 and September 1 of each year. We may redeem the 2016 Notes in whole or in part at our option beginning March 1, 2013, at the following redemption prices: 104.875% after March 1, 2013, 102.4375% after March 1, 2014, and 100% after March 1, 2015. In addition, we may, at our option, redeem up to an aggregate of 35% of the 2016 Notes before March 1, 2012, at a price of 109.75%. The indenture governing the 2016 Notes contains certain restrictions on our ability to incur additional debt, pay dividends on our common stock, make investments, create liens on our assets, engage in transactions with our affiliates, transfer or sell assets, consolidate or merge, or sell substantially all of our assets. The 2016 Notes are not subject to any sinking fund requirements. All of our subsidiaries, other than minor subsidiaries, guarantee this debt jointly and severally.

8¼% Senior Subordinated Notes due 2020

In February 2010, we issued $1.0 billion of 8¼% Senior Subordinated Notes due 2020 (the “2020 Notes”), for net proceeds after underwriting discounts and commissions of $980 million. The 2020 Notes, which carry a coupon rate of 8.25%, were sold at par. We subsequently redeemed $3.7 million principal amount of the 2020 Notes, as required under the indenture governing the 2020 Notes. See Tender Offers and Consent Solicitations for Encore’s Senior Subordinated Notes; Supplements to Indentures Governing Encore’s Senior Subordinated Notes above.

The 2020 Notes mature on February 15, 2020, and interest is payable on February 15 and August 15 of each year. We may redeem the 2020 Notes in whole or in part at our option beginning February 15, 2015, at the following redemption prices: 104.125% after February 15, 2015, 102.75% after February 15, 2016, 101.375% after February 15, 2017, and 100% after February 15, 2018. Prior to February 15, 2013, we may, at our option, redeem up to an aggregate of 35% of the principal amount of the 2020 Notes at a price of 108.25% with the proceeds of certain equity offerings. In addition, at any time prior to February 15, 2015, we may redeem 100% of the principal amount of the 2020 Notes at a price equal to 100% of the principal amount plus a “make-whole” premium and accrued and unpaid interest. The indenture governing the 2020 Notes contains certain restrictions on our ability to incur additional debt, pay dividends on our common stock, make investments, create liens on our assets, engage in transactions with our affiliates, transfer or sell assets, consolidate or merge, or sell substantially all of our assets. The 2020 Notes are not subject to any sinking fund requirements. All of our subsidiaries, other than minor subsidiaries, guarantee this debt jointly and severally.

6 % Senior Subordinated Notes due 2021

In February 2011, we issued $400 million of 6 % Senior Subordinated Notes due 2021 (“2021 Notes”). The 2021 Notes, which carry a coupon rate of 6.375%, were sold at par. The net proceeds of $393 million were used to repurchase a portion of our 2013 Notes and 2015 Notes (see 7½% Senior Subordinated Notes due 2013 and 7½% Senior Subordinated Notes due 2015 above). The 2021 Notes mature on August 15, 2021, and interest is payable on February 15 and August 15 of each year, beginning August 15, 2011. We may redeem the 2021 Notes in whole or in part at our option beginning August 15, 2016 at the following redemption prices: 103.188% on or after August 15, 2016; 102.125% on or after August 15, 2017; 101.062% on or after August 15, 2018; and 100% on or after August 15, 2019. Prior to August 15, 2014, we may at our option redeem up to an aggregate of 35% of the principal amount of the 2021 Notes at a price of 106.375% with the proceeds of certain equity offerings. In addition, at any time prior to August 15, 2016, we may redeem 100% of the principal amount of the 2021 Notes at a price equal to 100% of the principal amount plus a “make-whole” premium and accrued and unpaid interest. The indenture governing the 2021 Notes contains certain restrictions on our ability to incur additional debt, pay dividends on our common stock, make investments, create liens on our assets, engage in transactions with our affiliates, transfer or sell assets, consolidate or merge, or sell substantially all of our assets. The 2021 Notes are not subject to any sinking fund requirements. All of our subsidiaries, other than minor subsidiaries, guarantee this debt jointly and severally.

NEJD Financing and Free State Financing

In May 2008, we closed two transactions with 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. We recorded both of these transactions as financing leases.

Denbury Resources Inc.
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Debt Issuance Costs

In connection with the issuance of our outstanding long-term debt, the Company has incurred debt issuance costs, which are being amortized to interest expense using the effective interest method over the term of each related facility. Remaining unamortized debt issuance costs were $69.6 million and $74.8 million at December 31, 2011 and 2010, respectively. These balances are included in “Other assets” in our Consolidated Balance Sheets.

Indebtedness Repayment Schedule

At December 31, 2011, 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	
2012	$8,316
2013	10,148
2014	12,963
2015	10,603
2016	1,046,359
Thereafter	1,595,623
Total indebtedness	$2,684,012

Note 6. Income Taxes

Our income tax provision (benefit) is as follows:

	Year Ended December 31,		
In thousands	2011	2010	2009
Current income tax expense (benefit)			
Federal	$(12,552)	$15,683	$7,090
State	20,801	17,511	(2,479)
Total current income tax expense	8,249	33,194	4,611
Deferred income tax expense (benefit)			
Federal	329,715	143,381	(50,457)
State	12,748	16,968	(1,187)
Total deferred income tax expense (benefit)	342,463	160,349	(51,644)
Total income tax expense (benefit)	$350,712	$193,543	$(47,033)

We recognized current state and federal tax benefits during 2011 due to a change in treatment of certain items between our 2010 tax provision and our 2010 filed tax returns that reduced both state and federal current tax expense. This change in treatment resulted in a reclassification of approximately $16.9 million from current to deferred taxes.

At December 31, 2011, we had tax-effected federal net operating loss carryforwards (“NOLs”) totaling $14.0 million, state NOLs totaling $42.0 million, an estimated $53.4 million of enhanced oil recovery credits to carry forward related to our tertiary operations, and $34.8 million of alternative minimum tax credits. Our federal NOLs expire in 2031, while our state NOLs expire in various years, starting in 2015; however, the significant portion of our state NOLs begin to expire in 2023. Our enhanced oil recovery credits will begin to expire in 2023.

To the extent that tax deductions generated by the exercise of stock-based compensation reduce current taxes payable in a given period, a tax benefit is recorded for the excess of the tax deduction over the cumulative book compensation expense as additional paid-in capital. At December 31, 2011, our tax-effected federal tax loss carryforwards were approximately $21.0 million, of which $7.0 million relates to excess tax benefits from exercise of stock-based compensation. The income tax benefit from these stock-based compensation deductions will be recorded as an increase to additional paid-in capital upon utilization of the federal tax loss carryforwards.

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, 2011 and 2010 balance sheet dates. We believe that we will be able to realize all of our deferred tax assets at December 31, 2011, and therefore have provided no valuation allowance against our deferred tax assets.

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Significant components of our deferred tax assets and liabilities as of December 31, 2011 and 2010 are as follows:

	December 31,	
In thousands	2011	2010
Deferred tax assets:		
Loss carryforwards — federal	$13,970	$-
Loss carryforwards — state	41,960	44,595
Tax credit carryover	34,829	34,476
Derivative contracts	3,551	24,918
Enhanced oil recovery credit carryforwards	53,381	39,810
Stock based compensation	32,566	38,947
Other	35,279	45,950
Total deferred tax assets	215,536	228,696
Deferred tax liabilities:		
Property and equipment	(2,078,143)	(1,738,269)
Other	(5,813)	(10,965)
Total deferred tax liabilities	(2,083,956)	(1,749,234)
Total net deferred tax liability	$(1,868,420)	$(1,520,538)

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

	Year Ended December 31,		
In thousands	2011	2010	2009
Income tax provision (benefit) calculated using the federal statutory income tax rate	$323,416	$167,674	$(42,765)
State income taxes, net of federal income tax benefit	29,555	13,087	(3,666)
Revaluation of deferred tax liabilities, net	(578)	11,502	-
Other	(1,681)	1,280	(602)
Total income tax expense (benefit)	$350,712	$193,543	$(47,033)

In the third quarter of 2008, we obtained approval from the National Office of the Internal Revenue Service ("IRS") to change our method of tax accounting for certain assets used in our tertiary oilfield recovery operations. As a result of the approved change in method of tax accounting, beginning with the 2007 tax year we began to deduct, rather than capitalize, such costs for tax purposes, and applied for tax refunds associated with such change for our 2004 and 2006 tax years. Notwithstanding its consent to our change in tax accounting in 2008, the IRS exercised its prerogative to challenge the tax accounting method we used. In late January 2011, we received a Technical Advice Memorandum ("TAM") issued by the IRS National Office disapproving our method of accounting and revoking its consent to our change, on a prospective basis only, commencing January 1, 2011. Beginning with the 2011 tax year, we returned to capitalizing and depreciating the costs of these assets for tax purposes. As a result of the prospective nature of the IRS's determination, there was no change in our position with respect to the deductibility of these costs for 2007, 2008, 2009 and 2010. In December 2011, we received notification from the IRS that the review process was completed and that all issues related to the TAM were settled without further adjustments. Refund claims of $10.6 million for tax years through 2006 were received, plus accrued interest, in early 2012.

Uncertain Tax Positions

During 2011, as a result of settling the IRS audit through 2008, we removed the remaining uncertain tax position benefits of $0.2 million. Total unrecognized tax benefits were $0.2 million and $1.0 million as of December 31, 2010 and 2009, respectively. Our previously recognized uncertain tax positions related primarily to timing differences and did not materially impact our effective tax rate.

We file consolidated and separate income tax returns in the U.S. federal jurisdiction and in many state jurisdictions. The IRS concluded its examination of the Company’s 2006, 2007 and 2008 tax years during the fourth quarter of 2011 with no adjustments. In the fourth quarter of 2011, the IRS began its audit of Encore Acquisition Company and Subsidiaries, including Encore Operating LP, for the open tax years 2008, 2009 and 2010. The IRS has audited Encore Acquisition Company and Subsidiaries through tax year 2007. We are currently under examination by the state of Mississippi for the 2004, 2005, 2006 and 2007 tax years. We are also concurrently under examination by the state of Oklahoma for the 2010 tax year. We have not paid any significant interest or penalties associated with our income taxes, but classify both interest expense and penalties as part of our income tax expense.

Note 7. Stockholders' Equity

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. The program has no pre-established ending date, and may be suspended or discontinued at any time. 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 and December 31, 2011, we repurchased 14,112,610 shares of Denbury common stock (approximately 3.5% of our outstanding shares of common stock at September 30, 2011) at a cost of $195.2 million or $13.83 per share under this share repurchase program.

Our remaining share repurchases during 2011, and all of our share repurchases during 2010 and 2009 were from our employees who surrendered shares to the Company to satisfy their minimum tax withholding requirements as provided for under our stock compensation plans and were not part of a formal stock repurchase plan.

Employee Stock Purchase Plan

We have an Employee Stock Purchase Plan that is authorized to issue up to 9,900,000 shares of common stock. As of December 31, 2011, there were 1,277,516 authorized shares remaining to be issued under the plan. 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 75% Company match portion, which totaled $4.8 million, $3.5 million and $3.1 million for the years ended December 31, 2011, 2010 and 2009, 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 2011, 2010 and 2009, our matching contributions to the 401(k) Plan were approximately $7.1 million, $5.7 million and $4.0 million, respectively.

Note 8. Stock Compensation Plans

Stock Incentive Plans

We have two stock compensation plans. The first plan 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 1995 Plan provided only for the issuance of stock options, and in January 2005 we issued stock options under the 1995 Plan that utilized substantially all of the remaining authorized shares. The second plan, the 2004 Omnibus Stock and Incentive Plan (the "2004 Plan"), has a 10-year term and was approved by the stockholders in May 2004. The 2004 Plan provides for the issuance of incentive and non-qualified stock options, restricted stock awards, stock appreciation rights ("SARs") settled in stock, and performance awards that may be issued to officers, employees, directors and consultants. Awards covering a total of 29.5 million shares of common stock are authorized for issuance pursuant to the 2004 Plan, of which awards covering no more than 22.2 million shares may be issued in the form of restricted stock or performance vesting awards. At December 31, 2011, 9,700,640 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 vesting 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 four-year vesting period, with the specific terms of vesting determined at the time of grant based on guidelines established by 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 at 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.

In 2004, we began the use of restricted stock awards. The holders of these shares 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. Restricted stock awards vest over three-to-four-year vesting periods, with the specific terms of vesting determined at the time of grant.

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Beginning in 2007, the Board of Directors has awarded an annual grant of performance equity awards to officers of Denbury. These performance-based shares originally vested over 3.25 years, but beginning with awards granted in 2009, the vesting period was 1.25 years. The number of performance-based shares earned (and eligible to vest) during the performance period will depend on the Company's level of success in achieving four specifically identified performance targets. 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 number of shares will be earned if the higher maximum target levels are met. If performance is below the designated minimum levels for all performance targets, no performance-based shares will be earned. Any portion of the performance shares that are not earned by the end of the measurement period will be forfeited. In certain change of control events, one-half (i.e., the target level amount) of the performance-based shares would vest.

Stock-based compensation expense associated with our field employees is included in "Lease operating expense," while such expense associated with non-field employees is included in "General and administrative expense" in the Consolidated Statements of Operations. Stock-based compensation associated with Encore Merger transition employees is included in "Transaction and other costs related to the Encore Merger" 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, 2011, 2010 and 2009, respectively, are as follows:

	Year Ended December 31,		
In thousands	2011	2010	2009
Stock-based compensation expensed:			
General and administrative expense	$30,256	$28,169	$20,435
Lease operating expense	2,621	2,056	1,432
Transaction and other costs related to the Encore Merger	313	5,866	-
Total stock-based compensation expensed	33,190	36,091	21,867
Stock-based compensation capitalized	6,998	3,702	2,455
Total cost of stock-based compensation arrangements	$40,188	$39,793	$24,322
Income tax benefit recognized for stock-based compensation arrangements	$12,902	$14,359	$8,749

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 option is based on the U.S. Treasury yield curve in effect at the time of grant. The expected life of stock options and SARs granted was derived from examination of our historical option 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 stock. Implied volatility was not used in this analysis, as our tradable call option terms are short and the trading volume is low. Our dividend yield is zero, as we do not pay a dividend.

	2011	2010	2009
Weighted average fair value of SARs granted	$9.68	$8.45	$6.40
Risk-free interest rate	1.74 %	2.19 %	1.58 %

Expected life	4.0 to 5.0 years	4.0 to 4.3 years	3.9 to 4.7 years
Expected volatility	63.3 %	65.0 %	60.1 %
Dividend yield	-	-	-

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

	Year Ended December 31,					
	2011		2010		2009	
	Number of Awards	Weighted Average Exercise Price	Number of Awards	Weighted Average Exercise Price	Number of Awards	Weighted Average Exercise Price
Outstanding at beginning of period	12,269,340	$ 12.28	10,763,955	$ 10.77	9,514,999	$ 9.32
Granted	1,507,992	18.69	3,444,494	16.30	2,883,311	13.23
Exercised	(1,448,358)	6.97	(1,119,853)	6.21	(1,315,535)	4.33
Forfeited or expired	(379,364)	17.89	(819,256)	17.57	(318,820)	16.36
Outstanding at end of period	11,949,610	13.56	12,269,340	12.28	10,763,955	10.77
Exercisable at end of period	6,179,154	$ 10.18	6,214,546	$ 8.07	6,087,019	$ 6.48

The total intrinsic value of stock options and SARs exercised during the years ended December 31, 2011, 2010 and 2009, was approximately $20.5 million, $12.7 million and $14.8 million, respectively. The total grant-date fair value of stock options and SARs vested during the years ended December 31, 2011, 2010 and 2009, was approximately $11.4 million, $8.7 million and $10.1 million, respectively. The aggregate intrinsic value of stock options and SARs outstanding at December 31, 2011, was approximately $39.9 million, and these options and SARs have a weighted-average remaining contractual life of 4.2 years. The aggregate intrinsic value of options and SARs exercisable at December 31, 2011, was approximately $35.8 million, and these stock options and SARs have a weighted-average remaining contractual life of 3.4 years.

A summary of the status of our non-vested stock options and SARs as of December 31, 2011, and the changes during the year ended December 31, 2011, is presented below:

	Awards	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2010	6,054,794	$8.02
Granted	1,507,992	9.68
Vested	(1,452,626)	7.85
Forfeited	(339,704)	8.87
Non-vested at December 31, 2011	5,770,456	8.44

As of December 31, 2011, there was $20.4 million of total compensation cost to be recognized in future periods related to non-vested stock option and SAR share-based compensation arrangements. The cost is expected to be recognized over a weighted-average period of 2.2 years. Cash received from stock option exercises under share-based payment arrangements for the years ended December 31, 2011, 2010 and 2009, was $4.7 million, $4.9 million and $5.7 million, respectively. The tax benefit realized from the exercises of stock options and SARs totaled $0.9 million for 2011, $4.6 million for 2010, and $3.1 million for 2009.

Restricted Stock – 2004 Plan

As of December 31, 2011, there was $22.3 million of unrecognized compensation expense related to non-vested restricted stock grants. This unrecognized compensation cost is expected to be recognized over a weighted-average period of 2.6 years. The total vesting date fair value of restricted stock vested during the years ended December 31, 2011, 2010 and 2009 under the 2004 Plan was $12.4 million, $12.7 million and $10.0 million, respectively.

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A summary of the status of our non-vested restricted stock grants and the changes during the year ended December 31, 2011, is presented below:

	Shares	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2010	2,948,834	$13.70
Granted	1,134,627	18.83
Vested	(818,215)	15.89
Forfeited	(133,811)	17.74
Non-vested at December 31, 2011	3,131,435	14.82

Restricted Stock – Legacy Encore Plan

In February 2010, prior to the consummation of the Encore Merger, 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 Encore Merger, the shares were converted to shares of Denbury restricted stock. The shares vest ratably over a four-year graded vesting period; however, legacy Encore employees who terminate their employment for Good Reason, as defined by Encore's legacy Employee Severance Protection Plan, will automatically vest in their awards upon termination. Encore employees who did not accept permanent positions with Denbury but who continued their employment through a predefined transition period were considered to have terminated for Good Reason and, accordingly, vested in their awards upon termination. As of December 31, 2011, there was $2.3 million of unrecognized compensation expense related to non-vested restricted stock issued under the Encore Plan, which is expected to be recognized over a weighted-average period of 2.0 years. The total vesting date fair value of restricted stock vested during the years ended December 31, 2011 and 2010 under the Encore Plan was $2.3 million and $6.6 million, respectively.

A summary of the status of the non-vested restricted stock grants under the Encore Plan and the changes during the year ended December 31, 2011, is presented below:

	Shares	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2010	276,620	$15.42
Granted	-	-
Vested	(149,577)	15.43
Forfeited	(24,000)	15.43
Non-vested at December 31, 2011	103,043	15.43

Performance Equity Awards

During 2011, we granted performance-based equity awards (214,627 shares reflecting the 100% targeted vesting level) to the Company's officers, with an average grant-date fair value of $18.71 per share. The actual number of shares to be delivered pursuant to the performance-based awards could range from zero to 200% (429,254 shares) of the stated 100% targeted amount, although we currently estimate that shares to be delivered will approximate 56% of the targeted amount. During 2011, the performance-based equity awards originally granted in 2008 vested at 120% of their original targeted amount, resulting in the issuance of 115,056 shares of Denbury stock with a weighted average grant date fair value of $31.47 per share. Also during 2011, the performance-based equity awards originally granted in 2010 vested at 162% of their originally targeted amount, resulting in the issuance of 331,331 shares of Denbury stock with a weighted average grant-date fair value of $15.63 per share. The total vesting date fair value of performance-based equity awards during the years ended December 31, 2011 and 2010 was $10.9 million and $7.5 million, respectively. The Company recognizes compensation expense when it becomes probable that the performance criteria specified in the plan will be achieved.

Note 9. Derivative Instruments and Hedging Activities

Oil and Natural Gas 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 cash settlements of expired contracts, are shown under “Derivatives expense (income)” in our Consolidated Statements of Operations.

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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 consisted of price floors, collars and fixed price swaps. 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. We currently employ a strategy to hedge a portion of our forecasted production approximately 12 to 15 months in advance, as we believe it is important to protect our future cash flow to provide a level of assurance for our capital spending in those future periods in light of current worldwide economic uncertainties and commodity price volatility.

The following is a summary of "Derivatives expense (income)" included in our Consolidated Statements of Operations:

	Year Ended December 31,		
In thousands	2011	2010	2009
Oil			
Payment (receipt) on settlements of derivative contracts	$25,128	$93,417	$(146,734)
Fair value adjustments to derivative contracts – expense (income)	(58,980)	(44,441)	375,750
Total derivative expense (income) – oil	(33,852)	48,976	229,016
Natural gas			
Payment (receipt) on settlements of derivative contracts	(27,505)	(61,805)	-
Fair value adjustments to derivative contracts – expense (income)	8,860	(8,585)	7,210
Total derivative expense (income) – natural gas	(18,645)	(70,390)	7,210
Ineffectiveness on interest rate swaps	-	(2,419)	-
Derivative expense (income)	$(52,497)	$(23,833)	$236,226

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Commodity Derivative Contracts Not Classified as Hedging Instruments

						Contract Prices(1)		
						Weighted Average Price(2)		
Year	Months	Type of Contract	Volume(1)		Range	Swap	Floor	Ceiling
Oil Contracts:								
2012	Jan – Mar	Swap	625	$	80.28 – 81.75	$ 81.04	$ -	$ -
		Collar	52,000		70.00 – 139.60	-	70.00	106.86
		Put	625		65.00 – 65.00	-	65.00	-
	Total Jan – Mar 2012		53,250					
	Apr – June	Swap	625	$	80.28 – 81.75	$ 81.04	$ -	$ -
		Collar	53,000		70.00 – 137.50	-	70.00	119.44
		Put	625		65.00 – 65.00	-	65.00	-
	Total Apr – June 2012		54,250					
	July – Sept	Swap	625	$	80.28 – 81.75	$ 81.04	$ -	$ -
		Collar	53,000		80.00 – 140.65	-	80.00	128.57
		Put	625		65.00 – 65.00	-	65.00	-
	Total July – Sept 2012		54,250					
	Oct – Dec	Swap	625	$	80.28 – 81.75	$ 81.04	$ -	$ -
		Collar	53,000		80.00 – 140.65	-	80.00	128.57
		Put	625		65.00 – 65.00	-	65.00	-
	Total Oct – Dec 2012		54,250					
2013	Jan – Mar	Swap	-	$	-	$ -	$ -	$ -
		Collar	55,000		70.00 – 117.00	-	70.00	110.32
		Put	-		-	-	-	-
	Total Jan – Mar 2013		55,000					
		Swap	-	$	-	$ -	$ -	$ -

	Apr – June									
		Collar	42,000		75.00 – 118.00		-		75.00	115.91
		Put	-		-		-		-	-
	Total Apr – June 2013		42,000							
Natural Gas Contracts:										
2012	Jan – Dec	Swap	20,000	$	6.30 – 6.85	$	6.53	$	-	$ -
		Collar	-		-		-		-	-
		Put	-		-		-		-	-
	Total Jan – Dec 2012		20,000							

(1) Contract volumes are stated in BBl/d and MMBtu/d for oil and natural gas contracts, respectively.

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

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Additional Disclosures about Derivative Instruments:

At December 31, 2011 and 2010, we had derivative financial instruments recorded in our Consolidated Balance Sheets as follows:

Type of Contract	Balance Sheet Location	Estimated Fair Value Asset (Liability) December 31, 2011	2010
		In thousands	
Derivatives not designated as hedging instruments:			
Derivative Assets			
Crude oil contracts	Derivative assets – current	$ 23,452	$ 3,050
Natural gas contracts	Derivative assets – current	23,950	21,192
Crude oil contracts	Derivative assets – long-term	29	1,301
Natural gas contracts	Derivative assets – long-term	-	11,618
Derivative Liabilities			
Crude oil contracts	Derivative liabilities – current	(22,610)	(55,256)
Natural gas contracts	Derivative liabilities – current	-	-
Deferred premiums(1)	Derivative liabilities – current	(3,913)	(22,928)
Crude oil contracts	Derivative liabilities – long-term	(18,702)	(25,906)
Natural gas contracts	Derivative liabilities – long-term	-	-
Deferred premiums(1)	Derivative liabilities – long-term	(170)	(3,781)
Total derivatives not designated as hedging instruments		$ 2,036	$ (70,710)

(1) Deferred premiums payable relate to various oil and natural gas floor contracts and are payable on a monthly basis through December 2012.

Note 10. Fair Value Measurements

Fair value is the price that would be received to sell an asset or would be paid to transfer a liability in an orderly transaction between market participants at the measurement date (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 market 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. The Company's costless-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 from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Instruments in this category include non-exchange-traded natural gas derivatives swaps that are based on regional pricing other than NYMEX (i.e., Houston ship channel). The Company's basis swaps are estimated using discounted cash flow calculations based upon forward commodity price curves.

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

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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, 2011 and 2010:

	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, 2011				
Assets:				
Short-term investments	$86,682	$-	$ -	$86,682
Oil and natural gas derivative contracts	-	23,481	23,950	47,431
Liabilities:				
Oil and natural gas derivative contracts	-	(41,312)	-	(41,312)
Total	$86,682	$(17,831)	$ 23,950	$92,801
December 31, 2010				
Assets:				
Short-term investments	$93,020	$-	$ -	$93,020
Oil and natural gas derivative contracts	-	20,683	16,478	37,161
Liabilities:				
Oil and natural gas derivative contracts	-	(81,162)	-	(81,162)
Total	$93,020	$(60,479)	$ 16,478	$49,019

The following table summarizes the changes in the fair value of our Level 3 assets and liabilities for the years ended December 31, 2011 and 2010:

	Year Ended December 31,	
In thousands	2011	2010
Fair value of Level 3 instruments, beginning of year	$16,478	$-
Commodity derivative contracts acquired in Encore Merger	-	38,093
Unrealized gains (losses) on commodity derivative contracts included in earnings	13,384	21,240
Receipts on settlement of commodity derivative contracts	(5,912)	(42,855)
Fair value of Level 3 instruments, end of year	$23,950	$16,478
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	$13,384	$21,240

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

The carrying value of our revolving bank credit facility approximates fair value, as it is subject to short-term floating interest rates that approximate the rates available to us for those periods. The fair values of our senior subordinated notes are based on quoted market prices. The estimated fair value of our total long-term debt as of December 31, 2011 and 2010 is $2,638.2 million and $2,348.7 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. Leases entered into during 2011 have terms up to eleven years. Lease payments associated with these operating leases were $52.3 million, $42.4 million and $37.6 million in 2011, 2010 and 2009, respectively. We have subleased part of the office space included in our operating leases for which we received approximately $2.4 million, $0.5 million and $0.6 million in 2011, 2010 and 2009, respectively. In addition, we expect to receive approximately $2.0 million for 2012 and $0.3 million for 2013 under these sublease agreements.

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The following table summarizes by year the remaining non-cancelable future payments under these operating leases as of December 31, 2011:

In thousands	Pipeline Financing Leases	Capital Leases	Operating Leases
2012	$30,689	$2,206	$36,207
2013	32,469	1,447	37,509
2014	34,036	664	34,369
2015	31,847	106	33,536
2016	30,912	106	31,349
Thereafter	344,233	510	74,269
Total minimum lease payments	504,186	5,039	$247,239
Less: Amount representing interest	(260,912)	(651)	
Present value of minimum lease payments	$243,274	$4,388	

Commitments

We have entered into four long-term purchase commitments to purchase CO2 that are either non-cancelable or cancelable only upon the occurrence of specified future events. The commitments begin as early as 2012 and continue for up to 16 years. The price we will pay for CO2 varies depending on the amount of CO2 delivered and the price of oil. We anticipate the contracts will provide us with approximately 200 MMcf/d to 375 MMcf/d of CO2 at a cost of approximately $75 million – $135 million per year, assuming a $100 per Bbl NYMEX oil price. We have invested a total of $13.8 million in preferred stock of a proposed plant from which we would offtake CO2. All of our investment may later be redeemed, with a return or converted to equity after construction financing for the project has been obtained. We have recorded our investment in this security at cost and classified it as held-to-maturity, since we have the intent and ability to hold it until it is redeemed. The developer of the proposed plant is soliciting other potential investors for the project, and a third-party is currently engaged in due diligence. The investment is included in “Other assets” in our Consolidated Balance Sheets.

In conjunction with the August 1, 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. Subsequently, we amended this contract to provide for annual delivery (to the 8/8ths working interest) of 127 MMcf of helium (previously 200 MMcf) during the first two years of the contract and thereafter to provide for delivery of 400 MMcf per year. If the contracted quantity of helium is not supplied, we are obligated to compensate the third-party helium purchaser for the amount of the shortfall in an amount not to exceed $8.0 million per year.

Under the terms of our agreement to purchase Hastings Field in February 2009, we are required to make capital expenditures in Hastings Field of approximately $179 million prior to December 31, 2014. If we fail to spend certain amounts by specified interim due dates, we are required to make a cash payment equal to 10% of the cumulative shortfall at each applicable date. Further, we are committed to inject at least an average of 50 MMcf/day of CO2 (total of purchased and recycled) in the West Hastings Unit for the 90-day period prior to January 1, 2013. If such injections do not occur, we must either (1) relinquish our rights to initiate (or continue) tertiary operations and reassign to the seller all assets previously purchased for the value of such assets at that time based upon the discounted value of the field’s proved reserves using a 20% discount rate, or (2) make an additional payment of $20 million in January 2013, less any payments made for failure to meet the capital spending requirements as of December 31, 2012, and a $30 million payment for each subsequent year (less amounts paid for capital expenditure shortfalls) until the

CO_2 injection rate in the Hastings Field equals or exceeds the minimum required injection rate. At December 31, 2011, we are, and believe that we will continue to be, compliant with both of these commitments.

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 three CO_2 volumetric production payments ("VPPs"). See Note 13, Related Party Transactions – Genesis. Based upon the maximum amounts deliverable as stated in the industrial contracts and the volumetric production payments, we estimate that we may be obligated to deliver up to 327 Bcf of CO_2 to these customers over the next 14 years; however, since the group as a whole has historically purchased less CO_2 than the maximum allowed in their contracts, based on the current level of deliveries, we project that the amount of CO_2 that we will ultimately be required to deliver would likely be reduced to 240 Bcf. The maximum volume required in any given year is approximately 109 MMcf/d. Given the size of our Jackson Dome proven CO_2 reserves at December 31, 2011 (approximately 6.7 Tcf before deducting approximately 84.7 Bcf for the three VPPs), our current production capabilities and our projected levels of CO_2 usage for our own tertiary flooding program, we believe that we can meet these contractual delivery obligations.

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 or overall trends in 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 for litigation and claims if we determine that a loss is probable and the amount can be reasonably estimated.

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Other Contingencies

We are subject to audits in the various states in which we operate for sales and use taxes and severance taxes, 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. Supplemental Information

Significant Oil and Natural Gas Purchasers

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 do not expect that the loss of any purchaser would have a material adverse effect upon our operations. For the years ended December 31, 2011 and 2010, two purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company LLC (43% in 2011 and 46% in 2010) and Plains Marketing LP (16% in 2011 and 14% in 2010). For the year ended December 31, 2009, two purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company LLC (52%) and Hunt Crude Oil Supply Co. (21%).

Allowance for Doubtful Accounts

The Company records an allowance for doubtful accounts for receivables that the Company determines 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 $0.3 million and $0.5 million at December 31, 2011 and 2010, respectively.

Accounts Payable and Accrued Liabilities

	December 31,	
In thousands	2011	2010
Accrued exploration and development costs	$ 141,868	$ 101,758
Accounts payable	99,444	47,660
Accrued interest	60,923	57,077
Accrued compensation	35,861	39,757
Accrued lease operating expenses	24,185	23,557
Deferred Riley Ridge acquisition consideration	15,000	-
Taxes payable	13,455	34,371
Other	38,600	45,888
Total	$ 429,336	$ 350,068

Supplemental Cash Flow Information

In thousands, except shares	Year Ended December 31, 2011	2010	2009
Supplemental cash flow information:			
Cash paid for interest, expensed	$ 137,259	$ 151,831	$ 20,924
Cash paid for interest, capitalized	60,540	66,815	68,596
Cash paid for income taxes	45,912	17,960	16,002
Cash received from income tax refunds	24,677	15,107	15,761
Non-cash investing activities:			
Increase in asset retirement obligations	24,694	53,579	11,268
Increase (decrease) in liabilities for capital expenditures	74,697	(237)	(76,605)
Issuance of Denbury common stock in connection with the Encore Merger	-	2,085,681	-
Vanguard common units received as consideration for sale of ENP	-	93,020	-
Issuance of Denbury common stock pursuant to Conroe Field acquisition	-	-	168,723

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Note 13. Former Related Party Transactions – Genesis

During 2009, we held a 12% ownership interest in Genesis, which we disposed of during the first quarter of 2010.

Interest in and Transactions with Genesis

During February 2010, we sold our interest in Genesis Energy, LLC, the general partner of Genesis, which is a publicly traded master limited partnership. In March 2010, we sold all of our Genesis common units in a secondary public offering. As a result, we no longer hold any interests in Genesis, and Genesis is no longer considered a related party. Prior to these sales, we accounted for our 12% ownership in Genesis under the equity method of accounting. We received cash distributions from Genesis of $11.6 million in 2009.

Incentive Compensation Agreement

In late December 2008, our subsidiary, Genesis Energy, LLC, entered into agreements with three members of Genesis management for the purpose of providing them incentive compensation. The awards were mandatorily redeemable upon a change in control, and upon the sale of our interest in Genesis Energy, LLC, the change-in-control provision of each member's compensation agreement was triggered. As such, the awards were settled for cash in February 2010 for $14.9 million comprised of deferred compensation of $1.9 million and change of control redemption amounts of $13.0 million. In February 2010, we recognized general and administrative expense of $1.1 million associated with the $14.9 million payment. The remainder of the payment had been previously accrued in our financial statements as of December 31, 2009. We recorded approximately $14.2 million of expense during the year ended December 31, 2009, which is classified as "General and administrative" expenses on our Consolidated Statement of Operations.

Oil Sales and Transportation Services

We utilize Genesis' trucking services and common carrier pipeline to transport certain of our crude oil production to sales points where it is sold to third-party purchasers. We expensed $7.9 million in 2009 for these transportation services.

CO2 Volumetric Production Payments

During 2003 through 2005, we sold 280.5 Bcf of CO2 to Genesis under three separate volumetric production payment agreements. We have recorded the net proceeds of these volumetric production payment sales as deferred revenue and recognize such revenue as CO2 is delivered under the volumetric production payments. We recognized deferred revenue of $4.2 million for the year ended December 31, 2009 for deliveries under these volumetric production payments. In 2009, we recognized revenues of $5.5 million for certain processing and transportation services provided to Genesis.

Note 14. Subsequent Events

Equity Award Grant

In January 2012, we granted equity incentive awards to our employees under the 2004 Plan. The grant included 1,358,970 shares of restricted stock valued at $17.27 per share (the closing price of Denbury's common stock on January 6, 2012) and 775,663 SARs with an exercise price of $17.27 and a weighted average grant date fair value ranging between $9.03 and $9.15 per unit. The awards generally vest 25% per year over a four-year period.

Agreement to Sell Non-Core Gulf Coast Assets

On January 12, 2012, the Company entered into a definitive agreement with a privately held entity in which a member of our Board of Directors serves as Chairman of the Board, to sell certain non-core assets primarily located in central and southern Mississippi and in southern Louisiana for $155 million, subject to customary closing adjustments in a sale for which there was a competing bid contained in a multi-property purchase proposal. The sale is expected to close by late February 2012, subject to customary closing conditions, and would have an effective date of December 1, 2011.

Vanguard Common Units Sale

In January 2012, the Company sold its investment in Vanguard for cash consideration of $83.5 million, net of related transaction fees. In connection with the sale, the Company realized a pre-tax loss on the sale of $3.1 million, after consideration of "other-than-temporary" impairment charges recognized for the year ended December 31, 2011.

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Note 15. 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.

The Company capitalizes interest on unevaluated oil and natural gas properties that have ongoing development activities. Included in the costs incurred below is capitalized interest of $44.9 million in 2011, $32.6 million in 2010 and $14.3 million in 2009. 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 $24.2 million in 2011, $45.1 million in 2010 and $11.2 million in 2009. 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	2011	2010	2009
Property acquisitions:			
Proved	$ 86,465	$ 3,373,450	$ 585,637
Unevaluated	17,858	1,297,695	104,772
Exploration	31,483	8,728	4,635
Development	1,144,243	658,758	292,545
Total costs incurred (1)	$ 1,280,049	$ 5,338,631	$ 987,589

(1) Capitalized general and administrative costs that directly relate to exploration and development activities were $35.0 million, $20.1 million and $14.0 million for the years ended December 31, 2011, 2010 and 2009, 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	2011	2010	2009
Oil, natural gas and related product sales	$ 2,269,151	$ 1,793,292	$ 866,709
Lease operating costs	507,397	470,364	314,689
Marketing expenses	26,047	31,036	16,890
Taxes other than income	138,419	114,569	37,037
Depletion, depreciation and amortization	369,075	391,782	206,999

CO_2 depletion, depreciation and amortization (1)		24,460		29,206		29,076
Commodity derivative expense (income)		(52,497)		(21,414)		236,226
Net operating income		1,256,250		777,749		25,792
Income tax provision		477,375		295,545		9,927
Results of operations from oil and natural gas producing activities	$	778,875	$	482,204	$	15,865
Depletion, depreciation and amortization per BOE	$	16.42	$	15.82	$	13.39

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

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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. 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.

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 2011, 2010 and 2009 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 Reserves

	Year Ended December 31,								
	2011			2010			2009		
	Oil (MBbl)	Gas (MMcf)	Total (MBOE)	Oil (MBbl)	Gas (MMcf)	Total (MBOE)	Oil (MBbl)	Gas (MMcf)	Total (MBOE)
Balance at beginning of year	338,276	357,893	397,925	192,879	87,975	207,542	179,126	427,955	250,452
Revisions of previous estimates	(4,478)	(14,058)	(6,821)	3,538	16,171	6,233	(69)	(1,298)	(285)
Revisions due to price changes	2,558	485	2,639	2,780	811	2,915	4,557	(2,079)	4,211
Extensions and discoveries	42,936	52,339	51,658	26,313	130,245	48,021	334	11,785	2,298
Improved recovery(1)	264	-	264	30,173	-	30,173	13,875	-	13,875
Production	(22,169)	(10,783)	(23,966)	(21,870)	(28,491)	(26,619)	(13,495)	(24,764)	(17,622)
Acquisition of minerals in place	346	239,332	40,235	155,021	622,984	258,852	28,379	2,317	28,765
Sales of minerals in place	-	-	-	(50,558)	(471,802)	(129,192)	(19,828)	(325,941)	(74,152)
	357,733	625,208	461,934	338,276	357,893	397,925	192,879	87,975	207,542

Balance at end of year									
Proved Developed Reserves:									
Balance at beginning of year	219,077	110,516	237,496	116,192	69,513	127,778	96,746	298,114	146,432
Balance at end of year	239,741	125,970	260,736	219,077	110,516	237,496	116,192	69,513	127,778

(1) Improved recovery additions result from the application of secondary recovery methods such as water flooding, or tertiary recovery methods such as CO2 flooding.

Acquisitions of minerals in place during 2011 were primarily related to the acquisition of the remaining interest in Riley Ridge. Extensions and discoveries primarily include proved undeveloped reserves and were added primarily through additional drilling in the Bakken.

Acquisitions of minerals in place during 2010 were primarily from the Encore Merger and the Riley Ridge acquisition. The sales of minerals in place during 2010 were primarily due to the sale of the non-strategic Encore properties and our ownership interests in ENP. Extensions and discoveries primarily include reserves added at our Bakken and Haynesville fields. We added 39.4 MMBbls of tertiary proved oil reserves during 2010, primarily initial proved tertiary oil reserves at Delhi Field in Phase 5, plus upward revisions to reserves in other tertiary floods. In order to recognize proved tertiary oil reserves, we must either have an oil production response to CO2 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.

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.

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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 in calculating 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,		
	2011	2010	2009
Oil (NYMEX)	$96.19	$79.43	$61.18
Natural Gas (Henry Hub)	4.16	4.40	3.87

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	2011	2010	2009
Future cash inflows	$38,165,122	$26,698,819	$11,579,159
Future production costs	(12,570,015)	(9,702,896)	(5,034,393)
Future development costs	(3,026,898)	(1,912,457)	(836,455)
Future income taxes	(7,379,972)	(4,700,023)	(1,257,844)
Future net cash flows	15,188,237	10,383,443	4,450,467
10% annual discount for estimated timing of cash flows	(8,180,632)	(5,465,516)	(1,993,082)
Standardized measure of discounted future net cash flows	$7,007,605	$4,917,927	$2,457,385

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	2011	2010	2009
Beginning of year	$ 4,917,927	$ 2,457,385	$ 1,415,498
Sales of oil and natural gas produced, net of production costs	(1,597,288)	(1,177,322)	(498,093)
Net changes in sales prices	4,646,086	2,062,181	1,263,346
Extensions and discoveries, less applicable future development and production costs	762,370	295,074	6,735
Improved recovery(1)	15,708	623,622	202,145
Previously estimated development costs incurred	354,228	193,947	98,659
Revisions of previous estimates, including revised estimates of development costs, reserves and rates of production	(1,673,283)	(285,158)	(63,044)

Accretion of discount	729,234	307,546	192,686
Acquisition of minerals in place	29,737	3,671,439	365,771
Sales of minerals in place	-	(1,474,443)	(419,601)
Net change in income taxes	(1,177,114)	(1,756,344)	(106,717)
End of year	$ 7,007,605	$ 4,917,927	$ 2,457,385

(1) Improved recovery additions result from the application of secondary recovery methods such as water flooding or tertiary recovery methods such as CO2 flooding.

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Denbury Resources Inc.
Notes to Consolidated Financial Statements

Note 16. Supplemental CO2 and Helium Disclosures (Unaudited)

Based on engineering reports prepared by DeGolyer and MacNaughton, proved CO2 and helium reserves were estimated as follows (in MMcf):

	Year Ended December 31,		
	2011	2010	2009
CO2 Reserves			
Gulf Coast region(1)	6,685,412	7,085,131	6,302,836
Rocky Mountain region(2)	2,195,534	2,189,756	-
Helium Reserves Associated with Denbury's Production Rights			
Rocky Mountain region(3)	12,004	7,159	-

(1) Proved CO2 reserves in the Gulf Coast region consist of reserves from our reservoirs at Jackson Dome and are presented on a gross working interest basis, of which Denbury's net revenue interest was approximately 5.3 Tcf, 5.6 Tcf and 5.0 Tcf at December 31, 2011, 2010 and 2009, respectively, and include reserves dedicated to volumetric production payments of 84.7 Bcf, 100.2 Bcf and 127.1 Bcf at December 31, 2011, 2010 and 2009, respectively.

(2) Proved CO2 reserves in the Rocky Mountain region consist of our reserves at Riley Ridge and are presented on a gross working interest basis, of which Denbury's net revenue interest was approximately 1.6 Tcf and 0.9 Tcf at December 31, 2011 and 2010, respectively.

(3) Reserves associated with helium production rights include helium reserves located in the acreage in the Rocky Mountain region for which we have the right to extract the helium. The U.S. government retains title to the helium reserves and we retain the right to extract and sell the helium on behalf of the government in exchange for a fee. The helium reserves are presented net of the fee we will remit to the U.S. government.

Note 17. Unaudited Quarterly Information

In thousands, except per share amounts	March 31	June 30	September 30	December 31
2011				
Revenues and other income	$514,165	$601,397	$576,505	$617,257
Expenses	537,111	177,595	133,185	537,388
Net income (loss)	(14,190)	259,246	275,670	52,607
Net income (loss) per share:				
Basic	(0.04)	0.65	0.69	0.14
Diluted	(0.04)	0.64	0.68	0.13
Cash flow from operating activities	124,832	398,521	315,739	365,722
Cash flow used for investing activities	(285,043)	(347,797)	(525,412)	(447,706)
Cash flow provided by (used for) financing activities	(93,801)	(56,789)	112,244	76,314

2010				
Revenues and other income	$438,821	$497,210	$466,703	$519,057
Expenses	261,676	265,518	415,170	500,357
Net income	96,888	135,367	29,104	10,364
Net income per share:				
Basic	0.33	0.34	0.07	0.03
Diluted	0.32	0.34	0.07	0.03
Cash flow from operating activities	113,168	271,123	208,484	263,036
Cash flow provided by (used for) investing activities	(764,327)	505,713	(261,539)	165,373
Cash flow provided by (used for) financing activities	739,753	(818,547)	71,926	(132,885)

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company’s 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 the Company’s management, including our Chief Executive Officer and our Chief Financial Officer. Based on that evaluation, the Company’s Chief Executive Officer and our Chief Financial Officer concluded that the Company’s disclosure controls and procedures were effective as of December 31, 2011 to ensure: that information required to be disclosed in the reports it files and submits under the Securities Exchange Act of 1934 is recorded, 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 the Company's 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 2011, 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” 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 the Company’s internal control over financial reporting as of December 31, 2011 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.

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Denbury Resources Inc.

PART III

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 15, 2012 ("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.

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Denbury Resources Inc.

PART IV

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 58. 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 filed as part of this report.

Exhibit No.	Exhibit
2	Agreement and Plan of Merger by and between Encore Acquisition Company and Denbury Resources Inc. Executed on October 31, 2009 (incorporated by reference as Exhibit 2.1 of our Form 8-K filed on November 5, 2009).
3(a)	Restated Certificate of Incorporation of Denbury Resources Inc. filed with the Delaware Secretary of State on December 29, 2003 (incorporated by reference as Exhibit 3.1 of our Form 8-K filed on December 29, 2003).
3(b)	Certificate of Amendment of Restated Certificate of Incorporation of Denbury Resources Inc. filed with the Delaware Secretary of State on October 20, 2006 (incorporated by reference as Exhibit 3(a) of our Form 10-Q filed on November 8, 2005).
3(c)	Certificate of Amendment of Restated Certificate of Incorporation of Denbury Resources Inc. filed with the Delaware Secretary of State on November 21, 2007 (incorporated by reference as Exhibit 3(c) of our Form 10-K filed on February 29, 2008).
3(d)	Bylaws of Denbury Resources Inc., a Delaware corporation, adopted December 29, 2003 (incorporated by reference as Exhibit 3.2 of our Form 8-K filed on December 29, 2003).
3(e)	Amended and Restated Bylaws of Denbury Resources Inc. amended and restated as of June 27, 2011 (incorporated by reference from Exhibit 3.1 to our Form 8-K filed on June 21, 2011).
4(a)	Indenture for $420 million of 9.75% Senior Subordinated Notes due 2016 among Denbury Resources Inc., certain of its subsidiaries, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference as Exhibit 4.1 of our Form 8-K filed on February 17, 2009).
4(b)	First Supplemental Indenture to Indenture for $420 million of 9.75% Senior Subordinated Notes due 2016, dated as of June 30, 2009, between Denbury Resources Inc., as issuer, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference as Exhibit 4(h) of our form 10-K for the year ended 2009, filed on March 1, 2010).

4(c) Second Supplemental Indenture to Indenture for $420 million of 9.75% Senior Subordinated Notes due 2016, dated as of March 9, 2010, between Denbury Resources Inc., as issuer, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference as Exhibit 4.6 of our Form 8-K filed on March 12, 2010).

4(d) Third Supplemental Indenture to Indenture for $420 million of 9.75% Senior Subordinated Notes due 2016, dated as of February 3, 2011, between Denbury Resources Inc., as issuer, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference as Exhibit 4(p) of our Form 10-K for the year ended 2010, filed on March 1, 2011).

4(e) Indenture for $1 billion of 8¼% Senior Subordinated Notes due 2020 among Denbury Resources Inc., certain of its subsidiaries and Wells Fargo Bank, National Association, as Trustee (incorporated by reference as Exhibit 4.1 of our Form 8-K filed on February 12, 2010).

4(f) First Supplemental Indenture to Indenture for $1 billion of 8¼% Senior Subordinated Notes due 2020, dated as of March 9, 2010, among Denbury Resources Inc., certain of its subsidiaries and Wells Fargo Bank, National Association, as Trustee (incorporated by reference as Exhibit 4.7 of our Form 8-K filed on March 12, 2010).

4(g) Second Supplemental Indenture to Indenture for $1 billion of 8¼% Senior Subordinated Notes due 2020, dated as of February 3, 2011, among Denbury Resources Inc., certain of its subsidiaries and Wells Fargo Bank, National Association, as Trustee (incorporated by reference as Exhibit 4(s) of our Form 10-K for the year ended 2010, filed on March 1, 2011).

4(h) Indenture, dated as of April 2, 2004, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.25% Senior Subordinated Notes due 2014 (incorporated by reference as Exhibit 4.1.1 of our Form 8-K filed on March 12, 2010).

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4(i) First Supplemental Indenture, dated as of January 2, 2008, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.25% Senior Subordinated Notes due 2014 (incorporated by reference as Exhibit 4.1.2 of our Form 8-K filed on March 12, 2010).

4(j) Second Supplemental Indenture, dated as of January 27, 2010, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.25% Senior Subordinated Notes due 2014 (incorporated by reference as Exhibit 4.1.3 of our Form 8-K filed on March 12, 2010).

4(k) Third Supplemental Indenture, dated as of March 10, 2010, among Denbury Resources Inc. as successor in interest by merger to Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.25% Senior Subordinated Notes due 2014 (incorporated by reference as Exhibit 4.1.4 of our Form 8-K filed on March 12, 2010).

4(l) Fourth Supplemental Indenture, dated as of February 3, 2011, among Denbury Resources Inc., the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.25% Senior Subordinated Notes due 2014 (incorporated by reference as Exhibit 4(x) of our Form 10-K for the year ended 2010, filed on March 1, 2011).

4(m) Indenture, dated as of July 13, 2005, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.0% Senior Subordinated Notes due 2015 (incorporated by reference as Exhibit 4.2.1 of our Form 8-K filed on March 12, 2010).

4(n) First Supplemental Indenture, dated as of January 2, 2008, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.0% Senior Subordinated Notes due 2015 (incorporated by reference as Exhibit 4.2.2 of our Form 8-K filed on March 12, 2010).

4(o) Second Supplemental Indenture, dated as of January 27, 2010, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.0% Senior Subordinated Notes due 2015 (incorporated by reference as Exhibit 4.2.3 of our Form 8-K filed on March 12, 2010).

4(p) Third Supplemental Indenture, dated as of March 10, 2010, among Denbury Resources Inc., as successor in interest by merger to Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.0% Senior Subordinated Notes due 2015 (incorporated by reference as Exhibit 4.2.4 of our Form 8-K filed on March 12, 2010).

4(q) Fourth Supplemental Indenture, dated as of February 3, 2011, among Denbury Resources Inc., the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 6.0% Senior Subordinated Notes due 2015 (incorporated by reference as Exhibit 4(cc) of our Form 10-K for the year ended 2010, filed on March 1, 2011).

4(r) Indenture, dated as of November 16, 2005, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to Subordinated Debt Securities (incorporated by reference as Exhibit 4.3.1 of our Form 8-K filed on March 12, 2010).

4(s) First Supplemental Indenture, dated as of November 16, 2005, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 7.25% Senior Subordinated Notes due 2017 (incorporated by reference as Exhibit 4.3.2 of our Form 8-K filed on March 12, 2010).

4(t) Second Supplemental Indenture, dated as of January 2, 2008, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 7.25% Senior Subordinated Notes due (incorporated by reference as Exhibit 4.3.3 of our Form 8-K filed on March 12, 2010).

4(u) Third Supplemental Indenture, dated as of April 27, 2009, among Encore Acquisition Company, the subsidiary guarantors party thereto, and Wells Fargo Bank, National Association, with respect to the 9.50% Senior Subordinated Notes due 2016 (incorporated by reference as Exhibit 4.3.4 of our Form 8-K filed on March 12, 2010).

4(v) Fourth Supplemental Indenture, dated as of January 27, 2010, among Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 7.25% Senior Subordinated Notes due 2017 and the 9.50% Senior Subordinated Notes due 2016 (incorporated by reference as Exhibit 4.3.5 of our Form 8-K filed on March 12, 2010).

4(w) Fifth Supplemental Indenture, dated as of March 10, 2010, among Denbury Resources Inc., as successor in interest by merger to Encore Acquisition Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 7.25% Senior Subordinated Notes due 2017 and the 9.50% Senior Subordinated Notes due 2016 (incorporated by reference as Exhibit 4.3.6 of our Form 8-K filed on March 12, 2010).

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Denbury Resources Inc.

4(x) Sixth Supplemental Indenture, dated as of February 3, 2011, among Denbury Resources Inc., the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, with respect to the 7.25% Senior Subordinated Notes due 2017 and the 9.50% Senior Subordinated Notes due 2016 (incorporated by reference as Exhibit 4(jj) of our Form 10-K for the year ended 2010, filed on March 1, 2011).

4(y) Indenture dated as of February 17, 2011 among the Company, certain of the Company's subsidiaries as guarantors and Wells Fargo, National Association, as trustee, with respect to $400 million of 6 % Senior Subordinated Notes due 2021 (incorporated by reference as Exhibit 4.1 to our Form 8-K filed on February 22, 2011).

10(a) Credit Agreement, dated as March 9, 2010, among Denbury Resources Inc., as Borrower, the financial institutions listed on Schedule 1.1 thereto, as Banks, JPMorgan Chase Bank, N.A., as Administrative Agent, Banc of America Securities LLC, as Syndication Agent, and BNP Paribas, The Bank of Nova Scotia, and Credit Suisse Securities (USA) LLC, as Co-Documentation Agents (incorporated by reference as Exhibit 10.1 of our Form 8-K filed on March 12, 2010).

10(b) First Amendment to Credit Agreement dated as of March 9, 2010, dated as of May 13, 2010, among Denbury Resources Inc., as Borrower, the financial institutions listed on Schedule 1.1 thereto, as Banks, JPMorgan Chase Bank, N.A., as Administrative Agent, Banc of America Securities LLC, as Syndication Agent, and BNP Paribas, The Bank of Nova Scotia, and Credit Suisse Securities (USA) LLC, as Co-Documentation Agents (incorporated by reference as 10.1 of our Form 8-K filed on May 19, 2010).

10(c) Second Amendment to Credit Agreement dated as of March 9, 2010, dated as of September 30, 2010, among Denbury Resources Inc., as Borrower, the financial institutions listed on Schedule 1.1 thereto, as Banks, JPMorgan Chase Bank, N.A., as Administrative Agent, Banc of America Securities LLC, as Syndication Agent, and BNP Paribas, The Bank of Nova Scotia, and Credit Suisse Securities (USA) LLC, as Co-Documentation Agents (incorporated by reference as Exhibit 10.1 to our Form 10-Q filed on November 9, 2010).

10(d) Third Amendment to Credit Agreement dated as of March 9, 2010, dated as of December 17, 2010, among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference as Exhibit 10(d) of our Form 10-K for the year ended 2010, filed on March 1, 2011).

10(e) Fourth Amendment to Credit Agreement dated as of March 9, 2010, dated as of February 1, 2011, among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference as Exhibit 10(e) of our Form 10-K for the year ended 2010, filed on March 1, 2011).

10(f)	Pipeline Financing Lease Agreement by and between Genesis NEJD Pipeline, LLC as Lessor, and Denbury Onshore, LLC, as Lessee, dated May 30, 2008 (incorporated by reference as Exhibit 99.1 of our Form 8-K filed on June 5, 2008).
10(g)	Transportation Services Agreement by and between Genesis Free State Pipeline, LLC and Denbury Onshore, LLC, dated May 30, 2008 (incorporated by reference as Exhibit 99.2 of our Form 8-K filed on June 5, 2008).
10(h)	Purchase and Sale Agreement, dated March 31, 2010, effective May 1, 2010, by and between Encore Operating, L.P., as Seller, and Quantum Resources Management, LLC, as Buyer (incorporated by reference as Exhibit 2.2 of our Form 10-Q, filed on May 10, 2010).
10(i)**	Denbury Resources Inc. Amended and Restated Stock Option Plan as of December 5, 2007 (incorporated by reference as Exhibit 99.2 of our Form 8-K, filed on December 11, 2007).
10(j)**	Denbury Resources Inc. Stock Purchase Plan, as amended and restated December 5, 2007 (incorporated by reference as Exhibit 99.4 of our Form 8-K, filed on December 11, 2007).
10(k)**	Form of indemnification agreement between Denbury Resources Inc. and its officers and directors (incorporated by reference as Exhibit 10 of our Form 10-Q for the quarter ended June 30, 1999).
10(l)**	Denbury Resources Inc. Directors Compensation Plan (incorporated by reference as Exhibit 4 of our Registration Statement on Form S-8, No. 333-39172, filed on June 13, 2000, amended on March 2, 2001 and May 11, 2006).
10(m)* **	Denbury Resources Severance Protection Plan, as amended and restated effective December 15, 2011.
10(n)**	Denbury Resources Inc. 2004 Omnibus Stock and Incentive Plan, as amended and restated effective December 30, 2008 (incorporated by reference as Exhibit 10(o) of our Form 10-K for the year ended December 31, 2008).
10(o)**	Denbury Resources Inc. Amendment to 2004 Omnibus Stock and Incentive Plan, dated effective as of December 31, 2010 (incorporated by reference as Exhibit 10(o) of our Form 10-K for the year ended 2010, filed on March 1, 2011).

10(p)* **	Denbury Resources Inc. Amendment to 2004 Omnibus Stock and Incentive Plan, dated effective as of December 15, 2011.
10(q)**	2004 Form of restricted stock award that vests 20% per annum for grants to officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(k) of our Form 10-K for the year ended December 31, 2004).
10(r)**	2004 Form of restricted stock award that vests on retirement for grants to officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(l) of our Form 10-K for the year ended December 31, 2004).
10(s)**	2004 Form of restricted stock award that vests 20% per annum for grants to directors pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(m) of our Form 10-K for the year ended December 31, 2004).
10(t)**	Form of deferred payment cash award that cliff vests 100% four years from the date of grant for grants to employees and officers (incorporated by reference as exhibit 10(bb) of our Form 10-K for the year ended December 31, 2005).
10(u)**	2006 Form of stock appreciation rights agreement that vests 100% four years from the date of grant for grants to employees and officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(w) of our Form 10-K for the year ended December 31, 2006).
10(v)**	2006 Form of stock appreciation rights agreement that cliff vests 100% four years from the date of grant for grants to directors pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(x) of our Form 10-K for the year ended December 31, 2006).
10(w)**	2006 Form of restricted stock award that vests 25% per annum for grants to new employees and officers on their hire date pursuant to 2004 Omnibus and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(y) of our Form 10-K for the year ended December 31, 2006).
10(x)**	2006 Form of restricted stock award that cliff vests 100% four years from the date of grant for grants to employees and officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(z) of our Form 10-K for the year ended December 31, 2006).
10(y)**	2007 Form of restricted stock award to officers that cliff vests on March 31, 2010 pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(y) of our Form 10-K for the year ended December 31, 2008).

10(z)**	2007 Form of performance share awards to officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(z) of our Form 10-K for the year ended December 31, 2007).
10(aa)**	2007 Form of restricted stock award to directors that cliff vests after three years pursuant to 2004 Omnibus Stock and Incentive Plan (incorporated by reference as Exhibit 10(cc) of our Form 10-K for the year ended December 31, 2007).
10(bb)**	2007 Form of restricted stock award to new directors that vests 20% per annum (incorporated by reference as Exhibit 10(z) of our Form 10-K for the year ended December 31, 2007).
10(cc)**	2008 Form of restricted stock award to certain officers that cliff vests on March 31, 2011 (incorporated by reference as Exhibit 10(b) of our Form 10-Q for the first quarter ended March 31, 2008).
10(dd)**	2008 Form of restricted stock award without change of control vesting to certain officers that cliff vests on March 31, 2011 (incorporated by reference as Exhibit 10(c) of our Form 10-Q for the first quarter ended March 31, 2008).
10(ee)**	2008 Form of performance share awards to certain officers with change of control vesting (incorporated by reference as Exhibit 10(d) of our Form 10-Q for the first quarter ended March 31, 2008).
10(ff)**	2008 Form of performance share awards to certain officers without change of control vesting (incorporated by reference as Exhibit 10(e) of our Form 10-Q for the first quarter ended March 31, 2008).
10(gg)**	2009 Form of restricted stock award to certain officers that cliff vests on March 31, 2012, pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(b) of our Form 10-Q for the quarter ended March 31, 2009).

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Denbury Resources Inc.

10(hh)**	2009 Form of restricted stock award without change of control vesting to certain officers that cliff vests on March 31, 2012, pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(c) of our Form 10-Q for the quarter ended March 31, 2009).
10(ii)**	2009 Form of performance share awards to certain officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(d) of our Form 10-Q for the quarter ended March 31, 2009).
10(jj)**	2009 Form of performance share awards without change of control vesting to certain officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(e) of our Form 10-Q for the quarter ended March 31, 2009).
10(kk)**	2009 Form stock appreciation rights to certain officers that cliff vests on March 31, 2012, pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(f) of our Form 10-Q for the quarter ended March 31, 2009).
10(ll)**	2009 Form of stock appreciation rights without change of control vesting pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(g) of our Form 10-Q for the quarter ended March 31, 2009).
10(mm)**	2010 Form of performance stock award pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 99.2 of our Form 8-K filed on May 25, 2010).
10(nn)**	2010 Form of performance cash award pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 99.3 of our Form 8-K filed on May 25, 2010).
10(oo)**	Founder’s Retirement Agreement by and between Denbury Resources Inc. and Gareth Roberts effective June 30, 2009 (incorporated by reference as Exhibit 10.1 of our Form 8-K filed on July 7, 2009).
10(pp)**	Amendment to Founder’s Retirement Agreement by and between Denbury Resources Inc. and Gareth Roberts effective as of October 6, 2010 (incorporated by reference in Form 8-K filed on October 12, 2010).
10(qq)**	$6.350 million 9.75% Senior Subordinated Note due 2016 issued on June 30, 2009 to Gareth Roberts (incorporated by reference as Exhibit 10.2 of our Form 8-K filed on July 7, 2009).
10(rr)	Fifth Amendment to Credit Agreement dated as of March 9, 2010, dated as of May 19, 2011 among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto

	(incorporated by reference from Exhibit 99.1 to our Form 8-K filed on May 20, 2011).
10(ss)	Sixth Amendment to Credit Agreement dated as of March 9, 2010, dated as of September 1, 2011 among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference from Exhibit 10.1 to our Form 8-K filed on September 8, 2011).
10(tt)**	2011 Form of Performance Stock Award pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference from Exhibit 10(a) to our Form 10-Q for the quarter ended March 31, 2011).
10(uu)**	2011 Form of Performance Cash Award pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference from Exhibit 10(b) to our Form 10-Q for the quarter ended March 31, 2011).
10(vv)**	Officer Resignation Agreement with Ronald T. Evans effective October 7, 2011 (incorporated by reference from Exhibit 10.1 to our Form 10-Q for the quarter ended September 30, 2011).
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.

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99*	The summary of DeGolyer and MacNaughton's Report as of December 31, 2011, on oil and gas reserves (SEC Case) dated January 31, 2012.

* Filed herewith.
** Compensation arrangements.

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Denbury Resources Inc.

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.

February 27, 2012	/s/ Mark C. Allen Mark C. Allen Sr. Vice President and Chief Financial Officer
February 27, 2012	/s/ Alan Rhoades 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.

February 27, 2012	/s/ Phil Rykhoek Phil Rykhoek Director, President and Chief Executive Officer (Principal Executive Officer)
February 27, 2012	/s/ Mark C. Allen Mark C. Allen Sr. Vice President and Chief Financial Officer (Principal Financial Officer)
February 27, 2012	/s/ Alan Rhoades Alan Rhoades Vice President and Chief Accounting Officer (Principal Accounting Officer)
February 27, 2012	/s/ Wieland Wettstein Wieland Wettstein Director
February 27, 2012	/s/ Michael Beatty Michael Beatty Director
February 27, 2012	/s/ Michael Decker Michael Decker Director
February 27, 2012	/s/ Ron Greene Ron Greene Director

February 27, 2012	/s/ David I. Heather David I. Heather Director
February 27, 2012	/s/ Greg McMichael Greg McMichael Director
February 27, 2012	/s/ Kevin Meyers Kevin Meyers Director

Denbury Resources Inc.

February 27, 2012	/s/ Gareth Roberts Gareth Roberts Director
February 27, 2012	/s/ Randy Stein Randy Stein Director
February 27, 2012	/s/ Laura Sugg Laura Sugg Director