PURE Denbury

2012 Annual Report

Denbury

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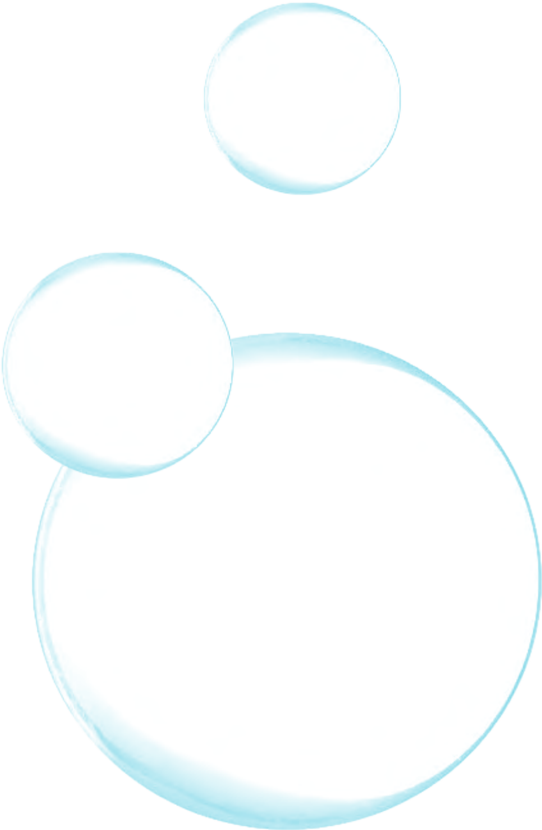


Forward-Looking Statements

The data contained in this annual report that are not historical facts are forward-looking statements that involve a number of risks and uncertainties. Such statements may relate to, among other things, forecasted capital expenditures, drilling activity, completion of acquisitions or reserves or future production attributable to them, development activities, timing of CO_2 injections and initial production response in tertiary flooding projects, estimated costs, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO_2 reserves, helium reserves, potential reserves from tertiary operations, future hydrocarbon prices or assumptions, liquidity, cash flows, availability of capital, borrowing capacity, finding costs, rates of return, overall economics, net asset values, estimates of potential or recoverable reserves and anticipated production growth rates in our CO_2 models, or estimated production in 2013 and future production and expenditure estimates, and availability and cost of equipment and services. These forward-looking statements are generally accompanied by words such as "estimated", "preliminary", "projected", "potential", "anticipated", "forecasted" or other words that convey the uncertainty of future events or outcomes. These statements are based on management's current plans and assumptions and are subject to a number of risks and uncertainties as further outlined in our most recent Form 10-K and Form 10-Q filed with the SEC. Therefore, the actual results may differ materially from the expectations, estimates or assumptions expressed in or implied by any forward-looking statement made by or on behalf of the Company.

Cautionary Note to U.S. Investors – Current SEC rules regarding oil and gas reserve information allow oil and gas companies to disclose in filings with the SEC not only proved reserves, but also probable and possible reserves that meet the SEC's definitions of such terms. We disclose only proved reserves in our filings with the SEC. Denbury's proved reserves as of December 31, 2012 were estimated by DeGolyer & MacNaughton, an independent petroleum engineering firm. In this annual report, we make reference to probable and possible reserves, some of which have been prepared by our independent engineers and some of which have been prepared by Denbury's internal staff of engineers. In this annual report, we also refer to estimates of original oil in place, resource "potential" or other descriptions of volumes potentially recoverable, which in addition to reserves generally classifiable as probable and possible (2P and 3P reserves), include estimates of reserves that do not rise to the standards for possible reserves, and which SEC guidelines strictly prohibit us from including in filings with the SEC. These estimates, as well as the estimates of probable and possible reserves, are by their nature more speculative than estimates of proved reserves and are subject to greater uncertainties, and accordingly the likelihood of recovering those reserves is subject to substantially greater risk.

Welcome to Denbury, a place where different is good. Here, we work to achieve our objectives and are accountable for our performance. We let our strategic vision for CO_2 EOR shape our goals. Welcome to a different kind of oil company. **Pure Denbury.**

PURE

FINANCIAL HIGHLIGHTS

In thousands, except per share data or otherwise noted	Year Ended December 31, 2012	2011	2010[1]	2009	2008
Consolidated Statements of Operations data:					
Revenues and other income :					
Oil, natural gas, and related product sales	$ 2,409,867	$ 2,269,151	$ 1,793,292	$ 866,709	$ 1,347,010
Other	46,605	40,173	128,499	22,441	24,046
Total revenues and other income	$ 2,456,472	$ 2,309,324	$ 1,921,791	$ 889,150	$ 1,371,056
Net income (loss) attributable to Denbury stockholders[2]	525,360	573,333	271,723	(75,156)	388,396
Net income (loss) per common share:					
Basic	1.36	1.45	0.73	(0.30)	1.59
Diluted	1.35	1.43	0.72	(0.30)	1.54
Weighted average number of common shares outstanding:					
Basic	385,205	396,023	370,876	246,917	243,935
Diluted	388,938	400,958	376,255	246,917	252,530
Consolidated Statements of Cash Flows data:					
Cash provided by (used by):					
Operating activities	$ 1,410,891	$ 1,204,814	$ 855,811	$ 530,599	$ 774,519
Investing activities	(1,376,841)	(1,605,958)	(354,780)	(969,714)	(994,659)
Financing activities	45,768	37,968	(139,753)	442,637	177,102
Production (average daily):					
Oil (Bbls)	66,837	60,736	59,918	36,951	31,436
Natural gas (Mcf)	29,109	29,542	78,057	68,086	89,442
BOE (6:1)	71,689	65,660	72,927	48,299	46,343
Unit sales prices — excluding impact of derivative settlements:					
Oil (per Bbl)	$ 97.18	$ 100.03	$ 75.97	$ 57.75	$ 92.73
Natural gas (per Mcf)	3.05	4.79	4.63	3.54	8.56
Unit sales prices — including impact of derivative settlements:					
Oil (per Bbl)	$ 96.77	$ 98.90	$ 71.69	$ 68.63	$ 90.04
Natural gas (per Mcf)	5.67	7.34	6.45	3.54	7.74
Costs per BOE:					
Lease operating expenses	$ 20.29	$ 21.17	$ 17.67	$ 17.85	$ 17.71
Taxes other than income	6.10	6.16	4.53	2.45	3.06
General and administrative expenses	5.49	5.24	5.04	5.77	3.36
Depletion, depreciation and amortization	19.34	17.07	16.32	13.52	13.08
Proved oil and natural gas reserves[3]:					
Oil (MBbls)	329,124	357,733	338,276	192,879	179,126
Natural gas (MMcf)	481,641	625,208	357,893	87,975	427,955
MBOE (6:1)	409,398	461,934	397,925	207,542	250,452
Proved carbon dioxide reserves:					
Gulf Coast region (MMcf)[4]	6,073,175	6,685,412	7,085,131	6,302,836	5,612,167
Rocky Mountain region (MMcf)[5]	3,495,534	2,195,534	2,189,756	—	—
Proved helium reserves associated with Denbury's production rights:[6]					
Rocky Mountain region (MMcf)	12,712	12,004	7,159	—	—
Consolidated Balance Sheets data:					
Total assets	$ 11,139,342	$ 10,184,424	$ 9,065,063	$ 4,269,978	$ 3,589,674
Total long-term liabilities	5,408,032	4,716,659	4,105,011	1,903,951	1,363,539
Stockholders' equity	5,114,889	4,806,498	4,380,707	1,972,237	1,840,068

(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 2009, we had a pretax charge of $236.2 million associated with our commodity derivative contracts.
(3) Estimated proved reserves as of December 31, 2012, reflect the disposition of reserves associated with our Bakken area assets sold in late 2012 (approximately 109 MMBOE). Year-end 2012 reserves reflect CCA reserves acquired in 2010 as part of the Encore Merger, but do not include estimated reserves of approximately 42 MMBOE related to the CCA Acquisition, which closed in March 2013.
(4) Proved CO_2 reserves in the Gulf Coast region consist of reserves from our reservoirs at Jackson Dome and are presented on a gross or 8/8ths working interest basis, of which our net revenue interest was approximately 4.8 Tcf, 5.3 Tcf, 5.6 Tcf, 5.0 Tcf and 4.5 Tcf at December 31, 2012, 2011, 2010, 2009 and 2008, respectively, and include reserves dedicated to volumetric production payments of 57.1 Bcf, 84.7 Bcf, 100.2 Bcf, 127.1 Bcf and 153.8 Bcf at December 31, 2012, 2011, 2010, 2009 and 2008, respectively. (See Note 15, *Supplemental* CO_2 *and Helium Disclosures (Unaudited)*, to the Consolidated Financial Statements.)
(5) Proved CO_2 reserves in the Rocky Mountain region consist of our reserves at Riley Ridge (presented on a gross working interest basis) and our overriding royalty interest in LaBarge Field, of which our net revenue interest was approximately 2.9 Tcf, 1.6 Tcf and 0.9 Tcf at December 31, 2012, 2011, and 2010, respectively.
(6) Reserves associated with helium production rights include helium reserves located in the acreage in the Rocky Mountain region for which we have the 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 estimate of helium reserves is reduced to reflect the related fee we will remit to the U.S. government.

DEAR SHAREHOLDERS:

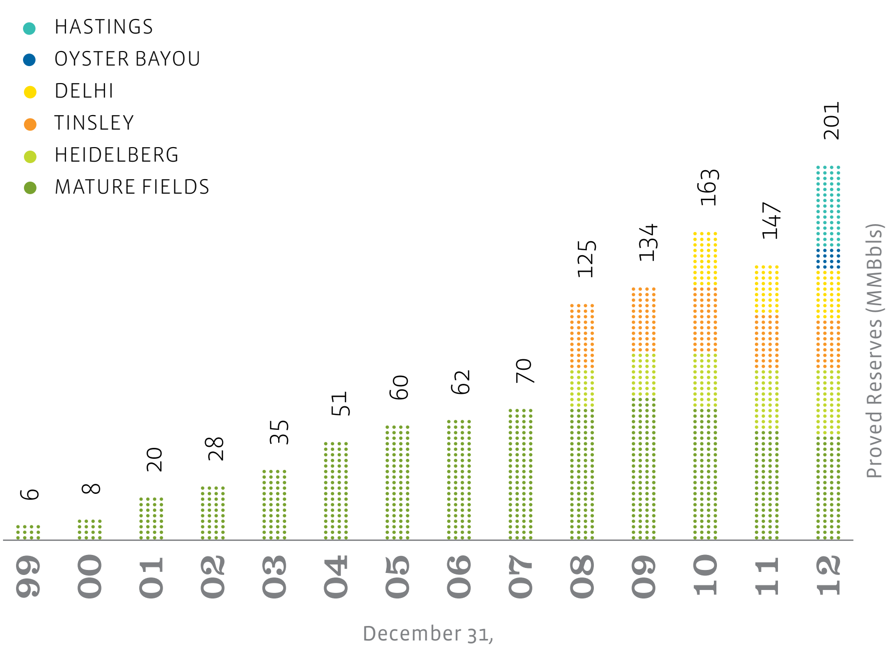
I am happy to report the past 12 months have been a very active and productive period at Denbury.

On the operational front, we delivered on our targets for the year as the actions we took to address the operational challenges we faced in 2011 proved successful. Quarterly oil production from our core business, enhanced oil recovery with carbon dioxide ("CO_2 EOR" or "tertiary recovery"), reached record levels as a result of continued expansion of our existing CO_2 floods and steady production growth at our two newest floods, Hastings and Oyster Bayou. With our strong tertiary production rates to-date in 2013, we are off to a positive start to the year and are optimistic about continuing to deliver on our production growth estimates.

On the transaction front, we've completed deals with over \$4 billion of aggregate value over the past 12 months.

The headline news for last year is the series of acquisitions and dispositions that aggregated over \$4 billion of value and have all been completed, on a tax efficient basis. This series of Company transforming transactions worked out even better than we had envisioned. Following are some of the highlights:

Proved Tertiary Oil Reserves
MMBBLS



Tinsley EOR facility

- We sharpened our strategic focus on CO_2 EOR where we have a strategic and competitive advantage, setting us up to be a pure CO_2 EOR play. Today, nearly every field we own is either a current or planned CO_2 EOR flood.
- We increased our potential CO_2 EOR reserves by nearly 210 million barrels which, even with the Bakken divestiture, results in a net increase in our total potential reserves. Further, we expect the additional potential CO_2 EOR will add more value for Denbury shareholders than the potential Bakken reserves that we sold. We estimate that we now have over 700 million barrels of potential CO_2 EOR reserves in our inventory, which gives us more than a decade of growth and will create substantial value for our shareholders.
- We nearly replaced the production of the sold assets with production from the acquired assets. This was accomplished with a corresponding minor impact on current cash flow.
- We exchanged proved reserves that were predominantly proved undeveloped for proved reserves that are primarily proved developed producing, which significantly increases our free cash flow (cash flow from operations less capital expenditures). In summary, our proved developed reserves increased as a result of the transactions while our total proved reserves decreased. More specifically, it would have required more than $1.7 billion of future capital expenditures to realize the proved undeveloped reserves associated with the sold Bakken assets. In contrast, the acquired assets will require less than $100 million of future development costs to realize the proved conventional reserves.
- In addition to the exchange of oil properties, with the net funds received from the transactions, we acquired 1.3 trillion cubic feet of Rocky Mountain region CO_2 reserves, with up to 115 million cubic feet per day of deliverability. These CO_2 reserves will allow us to develop one of the acquired oil fields in that region, Hartzog Draw, more quickly than would have been possible using our CO_2 reserves from Riley Ridge, our primary source of CO_2 reserves in the Rocky Mountain region. We also intend to use these CO_2 reserves for other future CO_2 EOR floods in the region.

The final component in this series of transactions, which we completed in March 2013, was the acquisition of ConocoPhillips' property interests in the Cedar Creek Anticline ("CCA") for $1.05 billion, before purchase price adjustments. We were able to structure the purchase as a like-kind-exchange, allowing us to defer approximately $400 million of taxes on the gain from our Bakken exchange transaction with ExxonMobil. This acquisition increased our interests in an area that was already our largest in the Rocky Mountain region. Consolidating our assets in this area should allow us to benefit from economies of scale and leverage our planned CO_2 transportation infrastructure. In fact, all of the future CO_2 EOR fields we acquired over the past 12 months are very close to existing or planned pipeline infrastructure, allowing us to amortize that pipeline cost over millions of additional barrels, and improving the returns on these incremental acquisitions.

While the headline news may be the acquisitions and dispositions, we had many other positive events during 2012. For example, we completed on-time and on-budget the construction of our first major CO_2 pipeline in the Rocky Mountain region. The initial 232-mile segment of the 20-inch Greencore pipeline connects the CO_2 coming from ConocoPhillips' Lost Cabin gas plant to our Bell Creek oil field. This pipeline is a strategic asset for us as it will ultimately be the backbone of our planned Rocky Mountain region pipeline infrastructure to transport CO_2 to our oil fields.

We completed on-time and on-budget the construction of our first major CO_2 pipeline in the Rocky Mountain region.

Another notable development in the past 12 months is that we began receiving our first man-made or anthropogenic CO_2 from Air Products in the Texas Gulf Coast region. CO_2 deliveries from this facility are expected to approach 50 million cubic feet per day later this year. This project illustrates our unique ability to use and store anthropogenic CO_2 that would otherwise be released in the atmosphere. We're highly encouraged by the opportunities we see to further expand our anthropogenic CO_2 sources in the coming years.

During 2012 we continued to opportunistically execute our common stock repurchase program initially authorized in 2011. We believe our stock has been undervalued, and even today our stock is trading below the net asset value of our proved oil and natural gas reserves and at levels that completely ignore the significant incremental value of our potential CO_2 EOR reserves. After a pause during the first three quarters of 2012, we resumed the repurchase program in earnest after we announced our Bakken exchange transaction, using the increased liquidity enabled by the Bakken disposition. As of the date of this letter, we have purchased approximately 35 million common shares or 9% of our outstanding shares when we began the program, at an average price of just over $15 per share. The program has benefitted all shareholders and has also improved our per-share metrics by approximately 9%. Our repurchase program remains in place with approximately $250 million remaining authorized, although our repurchases have slowed as our stock price has improved. We intend to be opportunistic with this program throughout 2013 depending on a number of factors.

Following our recent debt issuance, our capital structure is stronger than ever.

On the finance front, in early 2013 we issued $1.2 billion of long-term senior subordinated notes with a coupon rate of 4.625%. The interest rate for the notes was the lowest on record for a non-investment grade subordinated notes offering, which illustrates the market's confidence in our company and our outlook. Once fully expended, proceeds from the offering will have been used to repay about $650 million principal amount of subordinated notes with a weighted average interest rate of about 9.7%, with most of the remainder used to repay bank debt. Following the issuance, our capital structure is stronger than ever, with our next scheduled senior subordinated note maturity not until 2020.

In summary, it has been a remarkable past 12 months for Denbury. As we begin 2013, we are "PURE-ly" focused on what we do best: CO_2 EOR, which we believe offers one of the most compelling risk/reward profiles in the oil and gas industry today. We have excellent visibility on long-term oil production growth in our two core regions; our strong balance sheet provides us tremendous financial flexibility; and our workforce of highly technical, dedicated and motivated employees is focused on executing our unique strategy. We look forward to more positive results in 2013 and beyond as we continue to build on our highly profitable, lower-risk oil platform.

Sincerely,

Phil Rykhoek
President and Chief Executive Officer

March 28, 2013

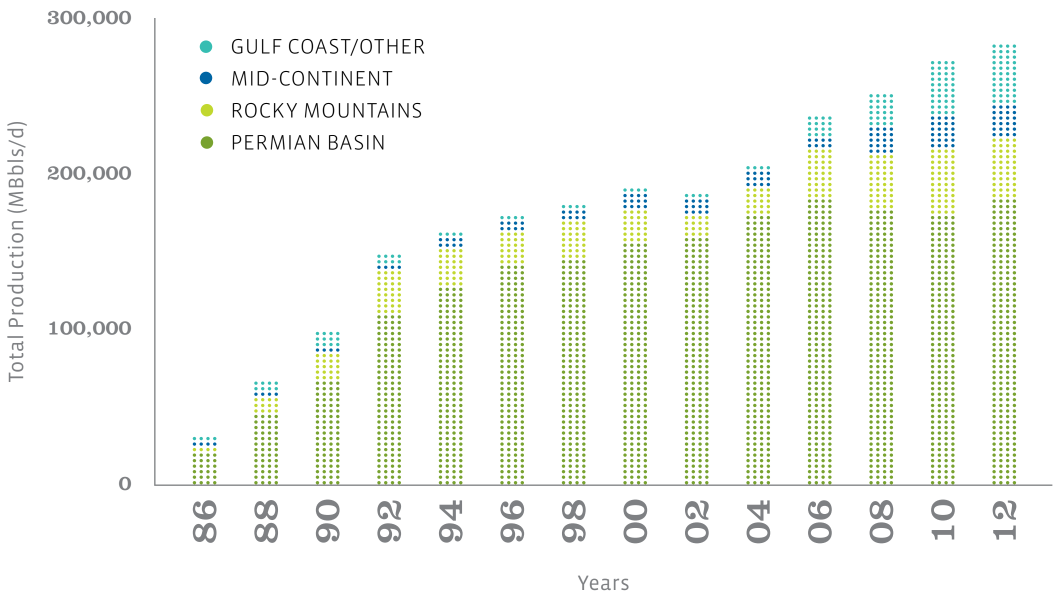
Proven process

CO_2 EOR is one of the most efficient tertiary oil recovery methods and is estimated to be capable of delivering as much production as primary or secondary recovery. Since 1999, we have grown our CO_2 EOR production at a compound annual rate of nearly 30% and have produced over 70 million barrels of oil from CO_2 EOR to-date. ***Pure Denbury.***

CO_2 EOR is a **Proven Process** that has been utilized for decades in a wide range of oil fields across North America. Total U.S. oil production using CO_2 EOR is estimated to be approaching 300,000 barrels per day from long-running and successful CO_2 floods in the Permian Basin, Rocky Mountain, Gulf Coast and Mid-Continent regions. CO_2 EOR is also being used to successfully increase oil production from several oil fields in western Canada.

Successfully executing a CO_2 EOR strategy requires four key components: 1) a large supply of CO_2; 2) oil fields with large amounts of oil in place that are well suited for CO_2 flooding (a good first indicator is whether a field has been successfully water flooded); 3) pipelines to transport the CO_2 from the source to the field; and 4) the proven technical and operational ability to install and operate a CO_2 flood. In most oil fields in the United States, primary and secondary oil recovery methods recover only up to about 40% of the original oil in place. When CO_2 is injected into oil bearing formations, it acts somewhat like a solvent, mixing with the oil and ultimately freeing the oil from the formation

TOTAL U.S. CO_2 EOR Oil Production by Region



Source: *Oil and Gas Journal,* July 2012

OUR CO_2 CYCLE CONSISTS OF THE FOUR STEPS ILLUSTRATED BELOW. WE CAPTURE CARBON DIOXIDE AND TRANSPORT IT TO MATURE OIL FIELDS TO INCREASE PRODUCTION AND CREATE NUMEROUS ECONOMIC AND SOCIAL BENEFITS.

1

STEP 1: CO_2 SOURCES & CAPTURE

We source CO_2 from Jackson Dome in Mississippi and from LaBarge and Lost Cabin in Wyoming. Additionally, we source anthropogenic (man-made) CO_2 volumes from industrial facilities and expect to obtain more anthropogenic CO_2 in the future. CO_2 capture occurs when anthropogenic CO_2 is purified and dried for transportation to oil fields.

STEP 4: CO_2 STRATEGIC BENEFITS

After the CO_2 EOR process is complete, the CO_2 is stored in the geological formation that originally trapped the oil. Oil production from our fields in the United States enriches local economies, royalty owners and our shareholders while reducing America's dependence on imported oil.

4

2

STEP 2: CO_2 TRANSPORTATION

We operate or control nearly 1,100 miles of CO_2 pipelines, more than 900 miles of which distribute CO_2 from Jackson Dome to oil fields we operate in the Gulf Coast region. In 2012, we completed the initial 232-mile segment of the 20-inch Greencore CO_2 pipeline, which will transport CO_2 from our sources to our operated oil fields in the Rocky Mountain region.

STEP 3: CO_2 EOR & STORAGE

Our CO_2 EOR operations allow us to recover significant amounts of otherwise stranded oil from existing oil fields while also providing a way to store anthropogenic CO_2.

3

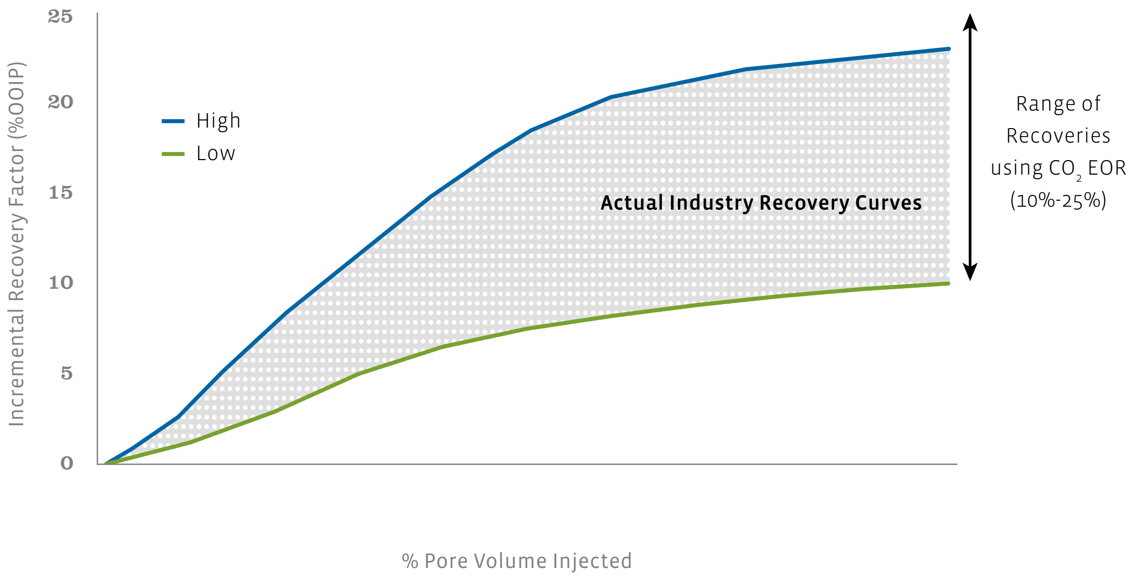
Our asset base today consists almost entirely of current and future CO_2 EOR projects.

as it moves through the reservoir rock. Our experience using this **Proven Process** has shown us that CO_2 EOR can allow us to produce as much as 50% more oil in a field that previously used primary and secondary recovery methods.

We began our CO_2 EOR operations in 1999, when we acquired Little Creek Field, followed by our acquisition of Jackson Dome CO_2 reserves and the NEJD pipeline in 2001. With our success at Little Creek and the ownership of CO_2 reserves and transportation infrastructure, we began to transition our capital spending and acquisition efforts to focus a greater percentage on CO_2 EOR. Over time, our strategy has transformed to focus almost exclusively on CO_2 EOR projects, and using this **Proven Process** we have grown our oil production from CO_2 EOR at a compound annual rate of nearly 30% over the last 13 years. We focus on consistently improving the process by utilizing the concepts we have successfully applied over the many years we have operated CO_2 EOR projects.

We believe using a **Proven Process** like CO_2 EOR involves less re-investment risk than more traditional oil & gas development, which requires companies to constantly look for and develop new oil plays. CO_2 EOR is utilized in oil fields that have significant historical production as well as reservoir and geological data that indicate large amounts of oil remain in the field that is recoverable through this process. Further, the results of our own and others' CO_2 floods indicate there is a higher range of certainty associated with the ultimate oil recovery with a CO_2 flood. The lowest incremental recovery factor from one of our CO_2 floods is still estimated to exceed 10% of the original oil in place ("OOIP"), while the highest recovery factor is estimated to exceed 20%. The data available on other companies' CO_2 floods indicates similar results across a large number of oil fields in numerous basins. In contrast,

Ranges of Oil Recovery from CO_2 EOR Projects



there is typically very little certainty a new oil play will result in economic oil production, even after significant capital investment.

The crux of our strategy to cost-effectively use this **Proven Process** revolves around purchasing a major anchor oil field in a geographic region known to contain a large number of prolific oil fields that still contain significant amounts of oil in place. After acquiring an anchor field, we build or acquire the necessary CO_2 supply and pipeline infrastructure, and then acquire other oil fields in the expansion area that we can flood with CO_2. We believe this concept works particularly well for incremental acquisitions, which generally have better economics because the significant infrastructure dollars are already invested and only minor CO_2 pipeline expansions are required.

Greencore Pipeline construction

We currently plan to grow our CO_2 EOR production for the next decade.

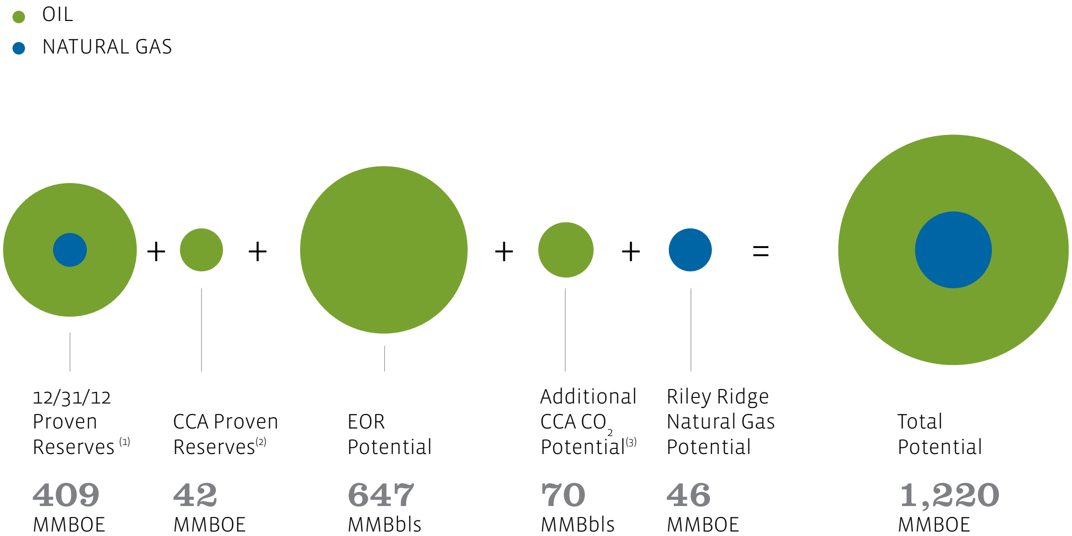
The key driver of our acquisition of Encore in 2010 was to expand our use of this **Proven Process** to the Rocky Mountain region, an area with long-established oil production and large amounts of oil in place. The anchor field in the acquisition was the Cedar Creek Anticline ("CCA") of Montana and North Dakota, with estimated OOIP of over three billion barrels. With the Encore acquisition came a significant acreage position in the Bakken oil shale play in North Dakota and Montana. After having increased the value of these Bakken-area assets from very little at the time we acquired them to nearly $2 billion, we entered into our Bakken exchange transaction with ExxonMobil. In the transaction, we leveraged our Bakken position to acquire prolific oil fields in both the Rocky Mountain and Gulf Coast regions that are candidates for CO_2 flooding, while also adding incremental CO_2 resources in the Rocky Mountain region. Perhaps just as importantly, we subsequently used $1.0 billion of the $1.3 billion cash proceeds from that deal to acquire additional producing property interests in the CCA from ConocoPhillips.

Our asset base today consists almost entirely of current and future CO_2 EOR projects. Of our total proved reserves of over 450 million barrels of oil equivalent at year-end 2012, inclusive of the recently completed CCA acquisition, approximately half come from CO_2 EOR projects. In addition to our proven reserves, we estimate our asset base holds nearly 770 million barrels of oil equivalent of potential reserves, approximately 94% of which are associated with CO_2 EOR projects. Through the development of our large resource base using this **Proven Process**, we currently plan to grow our CO_2 EOR production for the next decade.

Denbury's unique ability to store CO_2 while increasing oil production from otherwise depleted oil fields has provided strong production growth. Our strategy is supported by over 1,000 miles of CO_2 pipeline infrastructure and access to large CO_2 resources in the Gulf Coast and Rocky Mountain regions. ***Pure Denbury.***

Denbury is different from our peers in that our primary operational focus is CO_2 EOR. Our **Unique Strategy** is the result of the superior returns we have consistently generated from our CO_2 EOR operations and our strategic decision to make it our core business. We believe our CO_2 EOR recovery operations provide significant and sustainable production growth potential at attractive rates of return, with relatively low risk; accordingly, we expect CO_2 EOR will be the backbone of our growth for the foreseeable future. Successfully executing a CO_2 EOR strategy requires four key components: 1) a large supply of CO_2; 2) oil fields with large amounts of oil in place that are well suited for CO_2 flooding (a good first indicator is whether a field has been successfully water flooded); 3) pipelines to transport the CO_2 from the source to the field; and 4) the proven technical and operational ability to install and operate a CO_2 flood. We believe the reason CO_2 EOR is not more widespread is simply because most other oil companies do not have one of these critical components and thus usually face a significant barrier to entry.

More Than a Billion Barrels of Oil Potential



[1] Based on year-end 12/31/12 proved reserves prepared by DeGolyer and MacNaughton.
[2] Estimated year-end 12/31/12 proved reserves acquired in March 2013.
[3] Potential tertiary oil reserves estimate based on a variety of recovery factors.

U
nique
strategy

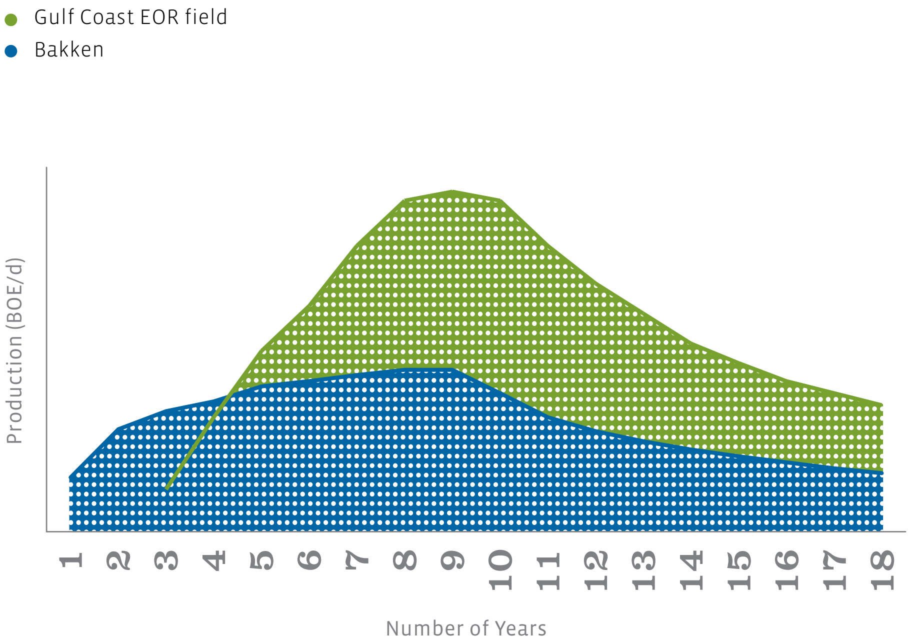
By controlling these four components, we expect to continue to generate strong returns from our CO_2 EOR operations for many years to come.

Our Unique Strategy is readily apparent in the strategic transactions we've completed over the past 12 months.

Our **Unique Strategy** is readily apparent in the strategic transactions we've completed over the past 12 months. The largest of these transactions involved the sale and exchange of our Bakken area assets with ExxonMobil. The Bakken oil shale play is currently one of the most active plays in the United States, and the acreage we owned in the play was desired by numerous oil and gas companies. ExxonMobil's desire to expand their Bakken-area interests meshed with our desire to expand our CO_2 EOR operations and Rocky Mountain CO_2 supply. As a result, we were able to consummate a transaction that we believe was a win for both parties.

With CO_2 EOR, we are using a proven process and are operating in oil fields that are known to still hold large reserves of oil. As a result, all of our CO_2 floods have generated positive returns on our investment. In contrast, a shale play may require a tremendous amount of investment to fully understand the play to determine that a sufficient amount of oil or gas is in place and can be economically recovered. Shale development, therefore, may have a wider range of outcomes early in the play. One of those outcomes may be that the play is deemed to be uneconomic, and no return is generated on the significant dollars invested.

Projected Production Profile with Same Capital Spending

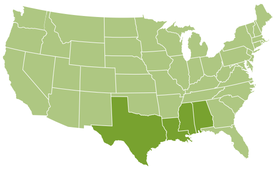


We expect to generate moderate production growth and free cash flow after the upfront infrastructure investments required to initiate a CO_2 flood are complete.

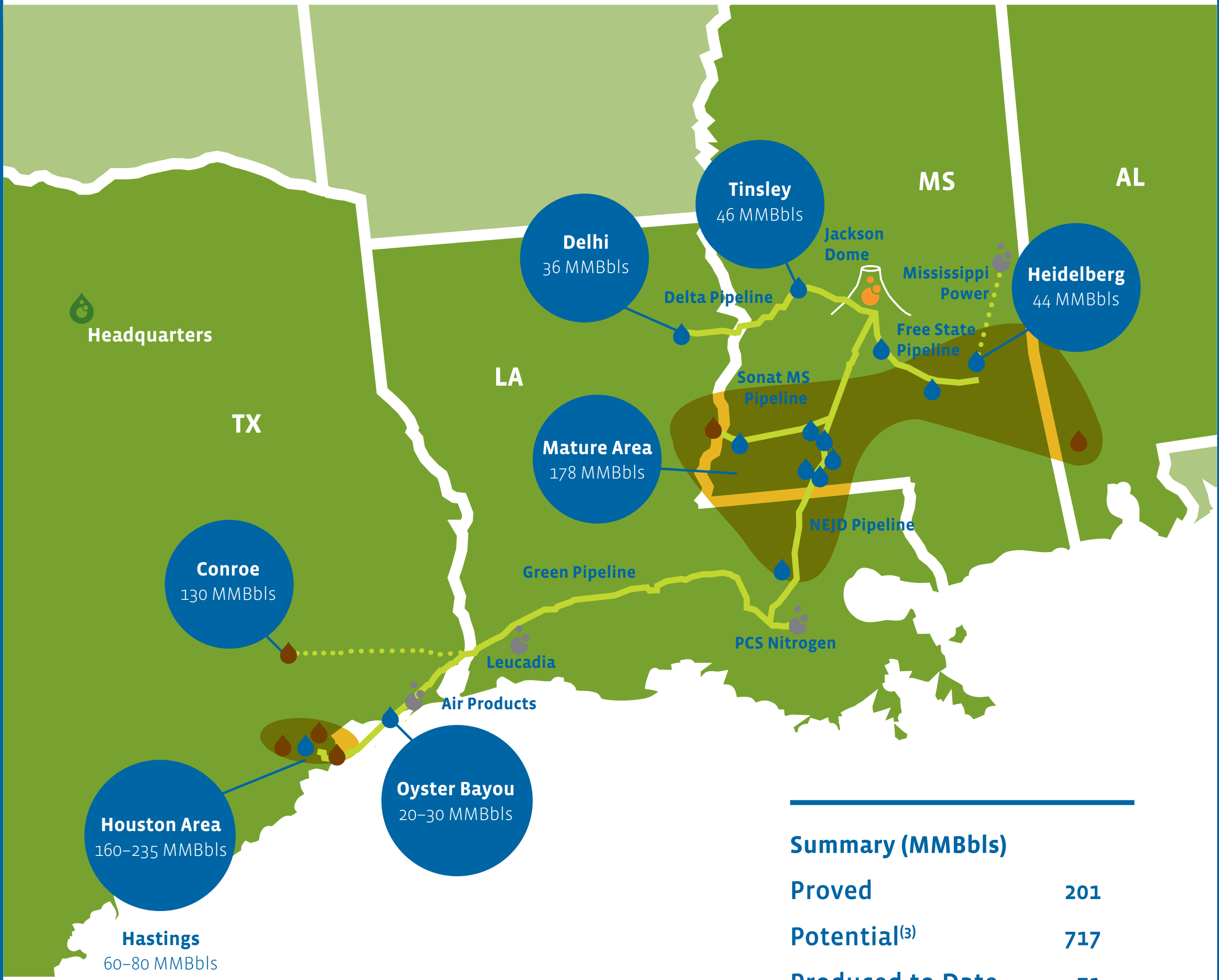
Another notable difference between CO_2 EOR and a shale play is the production type curves. Peak production from shale wells generally occurs when they are initially completed and the production rate may decline by over 50% in the first year. In contrast, a CO_2 flood typically requires several years to reach its peak production rate, and production may remain at this rate for a few years. It is these characteristics that we believe allow us to sustainably generate more production for a dollar we invest in a CO_2 flood than in a shale play. The rapid first-year decline rates typical of shale wells also create a growing investment "treadmill" that requires ever-growing amounts of capital to maintain production growth. In contrast, with a CO_2 flood we expect to generate modest production growth and free cash flow after the upfront infrastructure investments required to initiate a CO_2 flood are complete.

Operator at Hastings EOR facility

We currently estimate the total resource potential of our Gulf Coast and Rocky Mountain region assets at nearly 1.3 billion barrels of oil equivalent.



GULF COAST REGION: POTENTIAL TERTIARY OIL RESERVES[1]



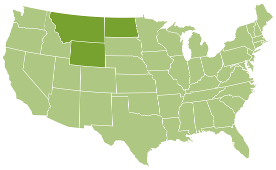
Hastings
60–80 MMBbls

Webster
60–75 MMBbls

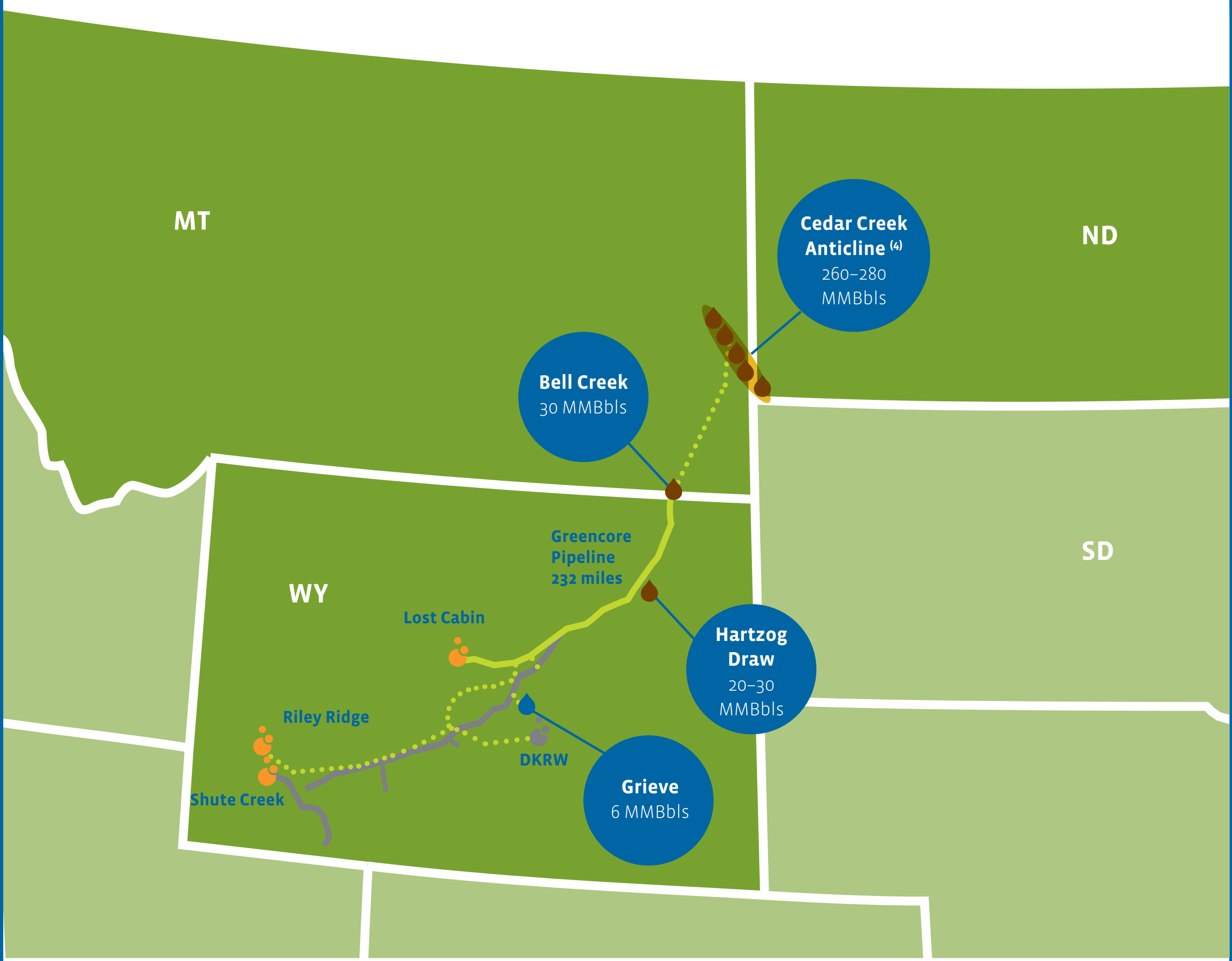
Thompson
30–60 MMBbls

Other
10–20 MMBbls

Summary (MMBbls)	
Proved	201
Potential[3]	717
Produced-to-Date	71
Total[3]	989



ROCKY MOUNTAIN REGION: POTENTIAL TERTIARY OIL RESERVES[2]



- Headquarters
- Existing Denbury CO_2 Pipelines
- Denbury Proposed CO_2 Pipelines
- CO_2 Pipelines Not Owned or Operated by Denbury
- Denbury CO_2 EOR Fields
- Denbury Future CO_2 EOR Fields
- CO_2 Reserves Owned
- Existing or Proposed Anthropogenic CO_2 Source Contracted

(1) Potential tertiary oil reserves as of 12/31/12, including past production, based on a range of recovery factors.
(2) Potential tertiary oil reserve estimates at 12/31/12, based on a range of recovery factors.
(3) Using mid-points of ranges.
(4) CCA includes recently closed acquisition.

Repeatable growth

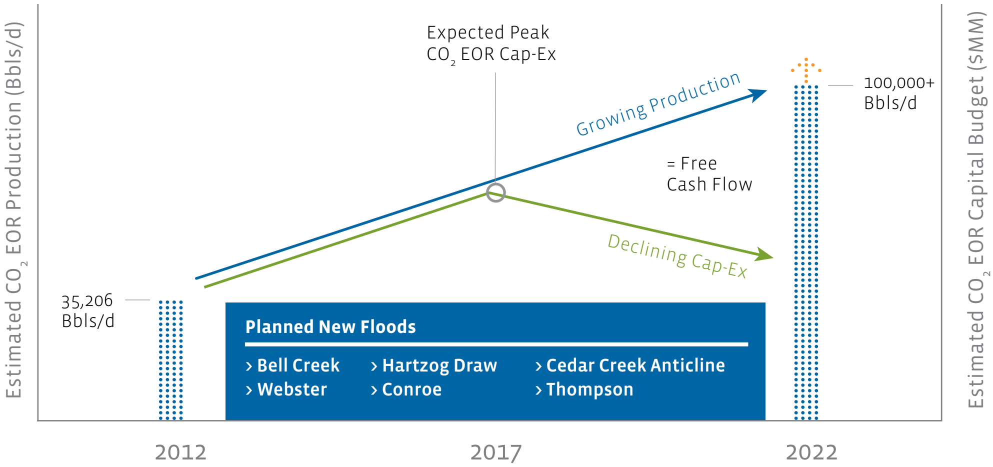
We anticipate a decade of CO_2 EOR production growth from existing fields. In 2012, we acquired additional fields that will allow us to build on our leading position in CO_2 EOR. ***Pure Denbury.***

Since 1999, we have consistently grown production from our CO_2 EOR operations from just over 1,000 barrels per day of oil from Little Creek Field to combined tertiary production of nearly 38,000 barrels of oil per day in the fourth quarter of 2012. Looking to the future, we see at least another decade of **Repeatable Growth** from our CO_2 EOR operations as we develop our existing inventory of projects.

With one of the most experienced CO_2 EOR teams in the industry, significant CO_2 reserves and transportation infrastructure, and a plentiful inventory of long-lived CO_2 EOR assets in the Gulf Coast and Rocky Mountain regions, together with a strong financial position, Denbury has a pure and powerful platform for **Repeatable Growth**. The planned development of our existing inventory of projects is expected to grow our CO_2 EOR production to over 100,000 barrels of oil per day by 2022, thereby creating significant value for our shareholders.

Our strategic and significant CO_2 supplies, ownership and control over 1,000 miles of CO_2 pipeline differentiate us from our peers and support our **Repeatable Growth** outlook. We own and operate the Jackson Dome Field, the only significant known natural source of CO_2 in the Gulf Coast region, allowing us to significantly grow our tertiary production. In addition to this natural

We Anticipate EOR Production Growth Through 2022[1]



(1) 2013 and future forecasted capital expenditures and production may differ materially from actual results. Does not include recently announced incremental CCA acquisition.

Owning and operating CO_2 pipeline infrastructure is a key element of our Repeatable Growth strategy.

source of CO_2, we have and continue to pursue man-made or anthropogenic sources of CO_2. We have entered into numerous contracts to purchase man-made CO_2 from existing or proposed plants or sources in the Gulf Coast region. We recently started receiving our first anthropogenic CO_2 into our Gulf Coast pipeline system from an industrial facility. We believe our CO_2 reserves at Jackson Dome, combined with current and expected future anthropogenic supplies, are sufficient to provide all of the CO_2 for our existing and currently planned tertiary operations in the Gulf Coast region.

In the Rocky Mountain region, we acquired approximately a one-third ownership interest (in the form of an overriding royalty interest) in ExxonMobil's LaBarge Field's CO_2 reserves in 2012 as part of our Bakken exchange transaction. Based on current capacity, we expect to receive up to approximately 115 MMcf/d of CO_2 from their facility. The CO_2 we receive from LaBarge, combined with what we expect to produce from our Riley Ridge facility, will be the backbone of our aggressive Rocky Mountain region CO_2 EOR expansion plans. We have also entered into contracts with existing and proposed gas plants to purchase CO_2, including ConocoPhillips' Lost Cabin gas plant in central Wyoming. We recently began purchasing CO_2 from the Lost Cabin facility and expect to start injecting the CO_2 into our Bell Creek Field in the first half of 2013.

Owning and operating CO_2 pipeline infrastructure is a key element of our **Repeatable Growth** strategy. We are growing our CO_2 pipeline network to reach targeted oil fields, and we currently operate or control nearly 1,100 miles of CO_2 pipelines. In 2010, we completed the construction of the Green Pipeline, which allowed us to start injecting CO_2 into Hastings Field, near Houston, Texas. 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. The 20-inch Greencore Pipeline in Wyoming is our first CO_2 pipeline in the Rocky Mountain region. As currently planned, the Greencore Pipeline will serve as our trunk line in the Rocky Mountain region, eventually connecting our Lost Cabin, LaBarge and Riley Ridge CO_2 sources to the CCA oil fields in eastern Montana. In 2012, we completed the initial 232-mile section of the Greencore Pipeline which begins at the Lost Cabin gas plant and terminates at the Bell Creek Field in Montana.

We've been developing oil fields in the Gulf Coast region with CO_2 EOR for over 13 years, and now operate 16 active floods. Most of our proved reserves growth in 2012 was attributable to the most recent floods at Oyster Bayou and Hastings fields. We also plan to flood additional large fields in the Gulf Coast: the recently acquired Webster Field; Conroe Field, purchased a few years ago; and Thompson Field, acquired last year.

The Rocky Mountain region is an integral part of our Repeatable Growth outlook.

We acquired the first Rocky Mountain region oil fields that we plan to develop with CO_2 EOR as part of the 2010 Encore acquisition. While we have significantly fewer oil fields and less CO_2 pipeline infrastructure in this region than in the Gulf Coast region, we are aggressively developing both. The Rocky Mountain region is an integral part of our **Repeatable Growth** outlook. With our acquisition of the Hartzog Draw Field in 2012, we now own four Rocky Mountain region fields that we plan to flood with CO_2, and we expect to acquire additional fields in the future. We recently commenced CO_2 injections into our first field in the region and expect to start injections into a second field in the first half of 2013. We expect our first Rocky Mountain tertiary oil production in the second half of 2013 from Bell Creek Field.

In reports released by the U.S. Department of Energy, it was estimated that the Gulf Coast region (Alabama, Mississippi, Louisiana and southeast Texas) originally contained approximately 79 billion barrels of oil in place. In the Rocky Mountain region (Montana, North Dakota, South Dakota and Wyoming), it was estimated that the original oil in place was approximately 36 billion barrels. Assuming that sufficient supplies of CO_2 are captured and delivered to the oil fields in these regions, the reports estimate that there are up to 7.5 billion barrels of OOIP in the Gulf Coast region and up to 3.2 billion barrels of oil in the Rocky Mountain region that could be recovered through CO_2 EOR. Our year-end 2012 estimated CO_2 EOR resource potential represented less than 10% of the estimated recoverable resources combined. Most of the other 90% of the estimated recoverable resource are in fields that we may acquire in the future to continue our **Repeatable Growth** for many, many years to come.

Welding at Hastings Field

CO_2 EOR allows us to use and store CO_2 captured from industrial facilities and results in net carbon reduction, even after considering the carbon created from the oil we produce. ***Pure Denbury.***

At Denbury, we strive to be **Environmentally Responsible** in all aspects of our operations. With our focus on CO_2 EOR, we offer several environmental benefits not generally associated with oil and gas operations. Perhaps most significantly, CO_2 EOR is increasingly being viewed as a strategy to reduce carbon emissions from various current and proposed industrial facilities. Our CO_2 EOR process provides an economical and technically feasible method of CO_2 disposal, making our nation more energy secure at the same time. Putting CO_2 to work as a commodity rather than as a waste is just common sense.

Many industrial facilities produce large volumes of CO_2, particularly fossil fuel power plants, chemical plants, and refineries. In these plants, carbon in the form of coal, oil or natural gas is combusted, releasing CO_2 as a byproduct and resulting in increasing amounts of CO_2 in our atmosphere. It has been proposed by those concerned about atmospheric CO_2 levels that these emissions be reduced by some means. Today, the only practical method of reducing CO_2 emissions is to store them in underground reservoirs. Our expanding CO_2 EOR operations provide an **Environmentally Responsible** method of transporting and storing these CO_2 volumes in oil reservoirs, while having the additional benefit of increasing domestic supplies of oil at the same time.


Reclaimed Green Pipeline habitat

Our CO_2 EOR projects inject approximately 0.52 to 0.64 metric tons of CO_2 for every barrel of oil recovered, compared to the 0.42 metric tons of CO_2 released when the oil is consumed. When we can use anthropogenic CO_2, these CO_2 EOR projects ultimately store between 24% and 52% more CO_2 than the recovered oil will release when the oil is utilized in a combustion process. There is no question that oil produced from CO_2 EOR using anthropogenic CO_2 has a smaller carbon footprint and is, therefore, more **Environmentally Responsible** than using oil that is produced by a method that stores no CO_2 emissions.

Because CO_2 EOR involves the development of existing oil fields, we have the ability to add to our nation's oil production with little, if any, additional environmental impact. Further, the mature oil fields that we acquire and develop often contain aging equipment and/or pipelines. As part of being

Environmentally responsible

Because CO_2 EOR is capital intensive, large sums of money are injected into local and state economies where we operate.

Environmentally Responsible stewards of these newly acquired properties, our process to increase oil production from mature oil fields with CO_2 EOR includes a comprehensive environmental assessment and remediation program that addresses environmental issues, equips the field with updated technology and results in a more environmentally benign operation that is cleaner and "greener" than what existed before.

In addition to our focus on environmental responsibility, Denbury constantly strives to be a **Responsible** member of the communities in which we live and work. We are proud of the numerous benefits our activities bring to these areas and to our country as a whole by reducing our dependence on imported oil. Because CO_2 EOR is capital intensive, we inject large sums of money into local and state economies where we operate. Reactivating and increasing oil production in mature oil fields results in increased revenue to the mineral owners; additional severance, ad valorem and sales tax revenues to state and local governments; and job growth that benefits local economies.

At Denbury, we encourage our employees to give generously and **Responsibly** to charitable organizations of their choice, and we support their contributions with our gift-matching program. Further, our employee-driven Charitable Contributions Committee seeks opportunities to support charitable organizations operating in the communities in which we work and operate through contributions and volunteer work.

Volunteers for Habitat for Humanity

BOARD OF DIRECTORS

Seated (left to right): Gregory L. McMichael Phil Rykhoek Michael L. Beatty Wieland F. Wettstein
Row 2 (left to right): Kevin O. Meyers Randy Stein Laura A. Sugg Michael B. Decker Ronald G. Greene

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

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

Michael B. Decker
Principal
Wingate Partners
Dallas, Texas

Ronald G. Greene
Principal
Tortuga Investment Corp.
Calgary, Alberta

Gregory L. McMichael
Independent Consultant
Denver, Colorado

Kevin O. Meyers
Independent Consultant
Houston, Texas

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

Randy Stein
Independent Consultant
Denver, Colorado

Laura A. Sugg
Independent Consultant
Katy, Texas

Our corporate governance guidelines, as well as the charters for our nominating/governance committee, reserves and HSE committee, compensation committee and audit committee, are listed on the Company website at www.denbury.com. The website also contains other corporate governance information such as our code of ethics for our directors, officers and employees; our hotline number to report any abnormalities; and other data.

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

OFFICERS

Phil Rykhoek
Director, President and Chief Executive Officer

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

K. Craig McPherson
Senior Vice President and Chief Operating Officer

Robert L. Cornelius
Senior Vice President — Commercial Development, Government Affairs and Project Management

Charlie Gibson
Senior Vice President — Planning, Technology and CO_2 Supply

James S. Matthews
Vice President, General Counsel and Secretary

Dan E. Cole
Vice President — Marketing and Business Development

Matt Elmer
Vice President — West Region

John E. Filiatrault
Vice President — CO_2 Supply and Pipeline

Jeff Marcel
Vice President — Drilling and EOR Facilities Engineering/Construction

Steve A. McLaurin
Vice President and Chief Information Officer

Alan Rhoades
Vice President and Chief Accounting Officer

Barry Schneider
Vice President — North Region

Whitney Shelley
Vice President and Chief Human Resources Officer

Phil Webb
Vice President — East Region

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

2012 FORM 10-K

(Mark One)

✓ Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2012
OR
___ Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from ______________ to ______________

Commission file number 1-12935

DENBURY RESOURCES INC.

(Exact name of Registrant as specified in its charter)

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

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

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

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

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

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

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a small reporting company. See definition of "large accelerated filer", "accelerated filer", and "small reporting company" in Rule 12-b2 of the Exchange Act.
Large accelerated filer ✓ Accelerated filer ___ Non-accelerated filer ___ Smaller reporting company ___

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

The aggregate market value of the registrant's common stock held by non-affiliates, based on the closing price of the registrant's common stock as of the last business day of the registrant's most recently completed second fiscal quarter was $5,050,462,439.

The number of shares outstanding of the registrant's Common Stock as of January 31, 2013, was 373,462,597.

DOCUMENTS INCORPORATED BY REFERENCE

Document:	Incorporated as to:
1. Notice and Proxy Statement for the Annual Meeting of Shareholders to be held May 22, 2013.	*1. Part III, Items 10, 11, 12, 13, 14*

Table of Contents

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, CO_2 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.
CO_2	Carbon dioxide.
EOR	Enhanced oil recovery.
Finding and Development Costs	The average cost per BOE to find and develop proved reserves during a given period. It is calculated by dividing 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, CO_2 or helium at a temperature base of 60 degrees Fahrenheit (°F) and at the legal pressure base (14.65 to 15.025 pounds per square inch absolute) of the state or area in which the reserves are located or sales are made.
Mcf/d	One thousand cubic feet of natural gas, CO_2 or helium produced per day.
MMBbls	One million barrels of crude oil or other liquid hydrocarbons.
MMBOE	One million BOEs.
MMBtu	One million Btus.
MMcf	One million cubic feet of natural gas, CO_2 or helium.
MMcf/d	One million cubic feet of natural gas, CO_2 or helium per day.
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.
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.
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 4 to the table included in Item 1, *Estimated Net Quantities of Proved Oil and Natural Gas Reserves and Present Value of Estimated Future Net Revenues – Oil and Natural Gas Reserve Estimates.*
Tcf	One trillion cubic feet of natural gas, CO_2 or helium.

* 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://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&rgn=div5&view=text&node=17:2.0.1.1.8&idno=17.

Item 1. Business and Properties

GENERAL

Denbury Resources Inc., a Delaware corporation, is a domestic independent oil and natural gas company with 409.4 MMBOE of estimated proved oil and natural gas reserves as of December 31, 2012, of which 80% is oil. Our primary focus is on enhanced oil recovery utilizing CO_2, and our operations are focused in two key operating areas: the Gulf Coast region and Rocky Mountain region. We are the largest combined oil and natural gas producer in both Mississippi and Montana, and we own the largest reserves of CO_2 used for tertiary oil recovery east of the Mississippi River. 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 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 CO_2 reserves, oil fields and CO_2 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. 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, 2012, we had 1,432 employees, 766 of whom were employed in field operations or at our field offices. We make our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports, filed or furnished pursuant to section 13(a) or 15(d) of the Securities Exchange Act of 1934, available free of charge on or through our 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 Annual Report on Form 10-K ("Form 10-K") we use the terms "Denbury," "Company," "we," "our," and "us" to refer to Denbury Resources Inc. and, as the context may require, its subsidiaries.

2012 BUSINESS DEVELOPMENTS

- Increased our average tertiary oil production to 35,206 Bbls/d in 2012, a 14% increase from average tertiary production in 2011 due to contributions from our newest CO_2 floods at Oyster Bayou and Hastings fields and expansion of our existing CO_2 floods at Tinsley, Heidelberg and Delhi fields.
- Added estimated proved tertiary reserves of 69.5 MMBbls, primarily including initial tertiary reserve bookings of 42.6 MMBbls at Hastings Field and 14.1 MMBbls at Oyster Bayou Field. The combined PV-10 value of the proved tertiary reserves at Hastings and Oyster Bayou fields at December 31, 2012 was $1.7 billion.
- Completed construction of the first section of the Greencore pipeline, our first CO_2 pipeline in the Rocky Mountain region, which is on schedule to begin deliveries of CO_2 from the Lost Cabin gas plant to our Bell Creek Field in Montana in the first half of 2013.
- Continued our share repurchase program, under which we repurchased a total of 17.0 million shares of Denbury common stock for $266.7 million during 2012, in addition to 14.1 million shares of Denbury common stock repurchased in 2011 for $195.2 million. As of February 21, 2013, we had spent a total of $521.0 million to repurchase an aggregate of 34.6 million shares, or approximately 8.6% of our outstanding shares as of September 30, 2011, at an average cost of $15.05 per share.

- Completed or entered into agreements on several strategic and tax efficient property transactions which not only add value, but as importantly, make us a nearly pure CO_2 EOR company. These asset transactions, which included both acquisitions and dispositions, aggregated (or upon completion will aggregate) over $4 billion in value, and (1) resulted in an increase in our unproven potential reserves, which we believe provides us a better opportunity to achieve a higher return due to the nature of the acquired properties compared to the sold properties, (2) nearly replaced the production of the sold assets with that from the acquired or to-be-acquired assets, (3) exchanged proved reserves with a high proved undeveloped component for reserves that are nearly all proved developed, which significantly increases our current free cash flow, (4) increased our Rocky Mountain CO_2 reserves by 1.3 Tcf and up to 115 MMcf/d of deliverability, and (5) positioned us to execute on our long-term strategy which we expect will increase shareholder value for many years to come. A summary of these transactions follows, with more detail on each significant transaction discussed further below:
    - Bakken Exchange Transaction – Divested our Bakken area assets, which were all non-tertiary, at an estimated value of approximately $2.0 billion, in exchange for interests in two future potential tertiary oil fields, a new Rocky Mountain region CO_2 source and $1.3 billion of cash.
    - Pending Cedar Creek Anticline Acquisition – Entered into an agreement in early 2013 to purchase additional interests in the Cedar Creek Anticline ("CCA") in Montana and North Dakota (the "Pending CCA Acquisition"), an area with future potential tertiary oil upside, for $1.05 billion, which will be funded with a portion of the cash proceeds from the Bakken Exchange Transaction. We expect to complete the Pending CCA Acquisition near the end of the first quarter of 2013.

In two separate transactions earlier in 2012, which were also structured as like-kind exchanges for federal income tax purposes, we completed the following:

- Acquisition of Thompson Field – Acquired a nearly 100% working interest and 84.7% net revenue interest in the Thompson Field in south Texas, a future potential tertiary oil field approximately 18 miles from our current EOR flood at Hastings Field, for $366.2 million.
- Sale of Non-core Assets – Sold our interests in non-core oil and natural gas fields in the Paradox Basin of Utah and in the Gulf Coast region for $68.5 million and $141.8 million, respectively.

Bakken Exchange Transaction. In late 2012, we closed a sale and exchange transaction with Exxon Mobil Corporation and its wholly-owned subsidiary XTO Energy Inc. (collectively, "ExxonMobil") under which we sold to ExxonMobil our Bakken area assets in North Dakota and Montana in exchange for $1.3 billion in cash (after preliminary closing adjustments) and EOR assets (the "Bakken Exchange Transaction"). By exchanging these non-tertiary Bakken area assets for EOR assets, we are able to more purely focus our attention on tertiary recovery operations.

The Bakken area assets we sold had proved reserves of approximately 109 MMBOE at the time of sale, of which 66% was undeveloped, and 2012 production through the third quarter of 15,850 BOE/d. The EOR assets acquired in the Bakken Exchange Transaction include: (1) Webster Field, a planned future tertiary field, located in southeastern Texas, with nearly 100% working interest and 80% net revenue interest, proved reserves of 3.7 MMBOE and production of approximately 1,000 BOE/d; (2) Hartzog Draw Field, a planned future tertiary field located in Wyoming, consisting of an 83% working interest and 71% net revenue interest in the oil-producing Shannon Sandstone zone and a 67% working interest and 53% net revenue interest in the natural gas-producing Big George Coal zone, with proved reserves of 5.2 MMBOE and production of approximately 2,600 BOE/d; and (3) approximately a one-third overriding royalty ownership interest in ExxonMobil's CO_2 reserves in LaBarge Field in Wyoming with proved reserves of 1.3 Tcf and estimated deliverability of up to 115 MMcf/d.

Pending CCA Acquisition. In January 2013, we entered into an agreement to acquire producing assets in the CCA of Montana and North Dakota from a wholly-owned subsidiary of ConocoPhillips for $1.05 billion in cash, before standard closing adjustments primarily for revenues and costs of the properties to be purchased from the January 1, 2013 effective date to the closing date. We plan to fund the acquisition with a portion of the cash proceeds from the Bakken Exchange Transaction in order to qualify the acquisition for like-kind-exchange treatment under federal income tax rules. We expect the Pending CCA Acquisition to close near the end of the first quarter of 2013.

The assets we plan to purchase from ConocoPhillips include both additional interests in certain of our existing operated fields in CCA as well as operating interests in other CCA fields. We currently estimate on a preliminary basis that, as of December 31, 2012, the proved conventional (non-tertiary) reserves associated with the acquired assets, net to our acquired interests, were approximately 42 MMBOE, of which approximately 99% is oil and natural gas liquids, with average daily production of approximately 11,000 BOE/d during the fourth quarter of 2012. We plan to incorporate the newly acquired CCA assets into our CO_2 development plan that is currently being designed and to extend the Greencore pipeline north and southwest in order to deliver the CO_2 necessary to flood the CCA assets.

Acquisition of Thompson Field. In June 2012, we acquired a nearly 100% working interest and 84.7% net revenue interest in Thompson Field for $366.2 million after preliminary closing adjustments. The field is located approximately 18 miles west of our Hastings Field, which we are currently flooding with CO_2, and which is the current terminus of the Green Pipeline which transports CO_2 from natural sources in the Jackson Dome area of Mississippi. Thompson Field is similar to Hastings Field, producing oil from the Frio zone at similar depths, and is a planned future tertiary field.

Sale of Non-Core Assets. On April 9, 2012, we completed the sale of certain non-operated assets in the Paradox Basin of Utah for $68.5 million cash after final closing adjustments. On February 29, 2012, we completed the sale of certain non-core assets primarily located in central and southern Mississippi and in southern Louisiana for $141.8 million, after final closing adjustments. We structured the sale of our non-core assets and the purchase of Thompson Field as a like-kind-exchange transaction for federal income tax purposes and anticipate deferral of a majority of the taxable gain recognized on the sale of the non-core assets.

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 non-controlling 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. In 2012, we exchanged the Bakken area assets acquired in the Encore Merger for cash and other assets with an estimated value of approximately $2.0 billion (see *2012 Business Developments – Bakken Exchange Transaction* above).

OIL AND NATURAL GAS OPERATIONS

Summary. Our oil and natural gas properties are concentrated in the Gulf Coast and Rocky Mountain regions of the United States. Currently our properties with proved and producing reserves in the Gulf Coast region are situated in Mississippi, Texas, Louisiana and Alabama, and in the Rocky Mountain region in Montana, North Dakota and Wyoming. Our primary focus is using CO_2 in EOR, which we have been doing since we acquired Little Creek Field in the Gulf Coast region in 1999. 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 CO_2 in the Rocky Mountain region. Our current portfolio of properties provides us significant growth potential for more than a decade.

Our Gulf Coast EOR operations are driven by CO_2 produced from natural sources in the Jackson Dome area of Mississippi, which is transported to our Gulf Coast tertiary fields. In late 2012, we received first deliveries of anthropogenic (man-made) CO_2 into the Gulf Coast pipeline system from an industrial facility in Port Arthur, Texas. The CO_2 for our Rocky Mountain EOR operations will initially be supplied from the Lost Cabin gas plant in Wyoming and from an overriding royalty interest equivalent to an approximate one-third ownership interest in ExxonMobil's CO_2 reserves in LaBarge Field, which overriding royalty interest we acquired during 2012 in the Bakken Exchange Transaction. In the future, we intend to utilize CO_2 from our Riley Ridge CO_2 source. In 2012, we completed the initial 232-mile segment of the 20-inch Greencore Pipeline, which will serve as part of the planned CO_2 trunk line in the region. Although our development of tertiary fields, CO_2 sources and pipelines in the Rocky Mountain region is just beginning, we believe that our significant CO_2 sources and planned pipeline infrastructure in the area will allow us to utilize CO_2 injection to potentially recover significant amounts of incremental oil from mature 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, 2012, and average daily production and net revenue interest ("NRI") for 2012. 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.

	Proved Reserves as of December 31, 2012(1)					2012 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 2012 NRI
Tertiary oil properties								
Gulf Coast region								
Mature properties:								
Brookhaven	10,938	—	10,938	2.7%	467,653	2,692	—	81.2%
Eucutta	9,251	—	9,251	2.3%	356,000	2,868	—	83.6%
Mallalieu	6,450	—	6,450	1.6%	222,586	2,338	—	78.0%
Other mature properties (3)	27,343	—	27,343	6.6%	865,308	7,707	—	73.3%
Delhi	25,038	—	25,038	6.1%	989,608	4,315	—	76.1%
Hastings	45,261	—	45,261	11.1%	1,179,241	2,188	—	82.7%
Heidelberg	34,599	—	34,599	8.5%	1,156,508	3,763	—	82.9%
Oyster Bayou	13,602	—	13,602	3.3%	496,501	1,388	—	87.0%
Tinsley	28,430	—	28,430	6.9%	1,085,180	7,947	—	80.6%
Total tertiary oil properties	200,912	—	200,912	49.1%	6,818,585	35,206	—	78.9%
Non-tertiary oil and gas properties								
Gulf Coast region								
Mississippi	6,408	28,165	11,102	2.7%	260,235	1,985	11,662	40.4%
Texas	33,694	17,861	36,671	9.0%	1,035,953	4,157	3,477	80.0%
Other	7,070	1,599	7,337	1.8%	180,805	1,087	902	22.0%
Total Gulf Coast region	47,172	47,625	55,110	13.5%	1,476,993	7,229	16,041	47.3%
Rocky Mountain region								
Cedar Creek Anticline (4)	66,792	425	66,863	16.3%	1,267,881	8,442	371	65.8%
Riley Ridge (5)	2	416,281	69,382	16.9%	22	—	96	54.8%
Other	14,246	17,310	17,131	4.2%	346,111	2,990	1,335	34.9%
Total Rocky Mountain region	81,040	434,016	153,376	37.4%	1,614,014	11,432	1,802	53.9%
Total continuing properties	329,124	481,641	409,398	100.0%	9,909,592	53,867	17,843	67.0%
Properties disposed in 2012								
Bakken area assets	—	—	—	—	—	12,539	11,140	
Gulf Coast assets	—	—	—	—	—	246	99	
Paradox assets	—	—	—	—	—	185	27	
Total	—	—	—	—	—	12,970	11,266	
Company total	329,124	481,641	409,398	100.0%	9,909,592	66,837	29,109	

(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 2012, which for NYMEX oil was $94.71 per Bbl, adjusted to prices received by field, and for natural gas was a Henry Hub cash price of $2.85 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 Standardized Measure was $6.4 billion at December 31, 2012. A comparison of PV-10 Value to the Standardized Measure is included in the reserves table in *Estimated Net Quantities of Proved Oil and Natural Gas Reserves and Present Value of Estimated Future Net Revenues* below. The information used to calculate PV-10 Value is derived directly from data determined in accordance with FASC Topic 932. See the definition of PV-10 Value in the *Glossary and Selected Abbreviations*.

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

(4) The Cedar Creek Anticline consists of a series of 10 producing oil units, each of which could be considered a field by itself. CCA reserves at December 31, 2012 do not include 42 MMBOE of currently estimated proved reserves we plan to acquire during the first quarter of 2013 through the Pending CCA Acquisition discussed above. See 2012 *Business Developments – Pending CCA Acquisition*.

(5) While the Riley Ridge Field reserves make up over 15% of the Company's total reserves, production from the field is currently negligible. We expect production to increase with the startup of the Riley Ridge gas plant in mid-2013.

Enhanced Oil Recovery Overview. CO_2 used in EOR is one of the most efficient tertiary recovery mechanisms for producing crude oil. The CO_2 acts somewhat like a solvent, mixing with the oil and ultimately freeing the oil from the formation as the CO_2 passes through reservoir rock. CO_2 tertiary floods are unique in that they require large volumes of CO_2. To our knowledge, the location of large quantities of naturally occurring CO_2 in the United States is limited to a few geological basins.

While enhanced oil recovery projects utilizing CO_2 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 and monitoring methods, (2) CO_2 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 CO_2 operations in August 1999, when we acquired Little Creek Field, followed by our acquisition of Jackson Dome CO_2 reserves and the NEJD pipeline in 2001. Based upon our success at Little Creek and the ownership of the CO_2 reserves, we began to transition our capital spending and acquisition efforts to focus a greater percentage on CO_2 EOR and, over time, transformed our strategy to focus primarily, and then almost exclusively, on CO_2 EOR projects. With the sale of our Bakken area assets in late 2012, our asset base today almost entirely relates to current or planned tertiary oil operations. We believe our investments, experience and acquired knowledge give us a strategic and competitive advantage in the areas in which we operate.

Our tertiary operations have grown so that (1) 49% of our proved reserves at December 31, 2012 are proved tertiary oil reserves; (2) approximately 54% of our forecasted 2013 production is expected to come from tertiary oil operations (on a BOE basis); and (3) approximately 85% of our 2013 planned capital expenditures are related to our tertiary oil operations. At year-end 2012, the proved oil reserves in our tertiary recovery oil fields had an estimated PV-10 Value of approximately $6.8 billion, using 12-month first-day-of-the-month unweighted average NYMEX pricing during calendar 2012 of $94.71 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 and time to construct such 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 our Gulf Coast projects at current oil prices is in the $40-per-barrel range, depending on the specific field and area), (3) we have limited competition for this type of activity in our geographic regions, and (4) our EOR activities could be considered more eco-friendly than other current oil and gas development, as we develop existing oil fields thereby not disturbing new habitats, drill fewer new wellbores, do not utilize hydraulic fracturing in our oil and natural gas development operations, and have the ability to geologically store CO_2 captured from industrial facilities.

We have been conducting and expanding EOR operations on our assets in the Gulf Coast region since 1999, and as a result, they are more developed from an EOR perspective than our assets in the Rocky Mountain region. In the Gulf Coast region, we own what is, to our knowledge, the only significant naturally occurring source of CO_2, and these large volumes of CO_2 have allowed us to significantly grow our production in that region. In addition to the sources of CO_2 we currently own, we are pursuing anthropogenic (man-made) sources of CO_2 to use in our tertiary operations, which we believe will not only help us recover additional oil, but will also provide an economical and eco-friendly way to store CO_2. We started receiving our first anthropogenic CO_2 in the fourth quarter of 2012 from an industrial facility in Port Arthur, Texas and expect the amount of CO_2 we use in our operations coming from anthropogenic sources to grow in the future.

Through December 31, 2012, we have invested a total of $3.0 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 $1.1 billion. Of this total invested amount, approximately $185 million (6%) was spent on fields that did not yet have any appreciable proved reserves at December 31, 2012. The proved oil reserves in our Gulf Coast tertiary oil fields have a year-end 2012 PV-10 Value of $6.8 billion, using the 12-month first-day-of-the-month unweighted average NYMEX pricing during calendar 2012 of $94.71 per Bbl. These amounts do not include the capital costs or related depreciation and amortization of our CO_2-producing properties or CO_2 pipelines, but do include CO_2 source field lease operating and transportation costs. Including the Green Pipeline, which currently services our Hastings and Oyster Bayou fields, we have invested a total of $2.0 billion in CO_2-producing assets and pipelines in the Gulf Coast region.

We began operations in the Rocky Mountain region in March 2010 as part of the Encore Merger, and as such, we have significantly fewer oil fields and less CO_2 pipeline infrastructure in that region, although we are aggressively developing both. We currently have four properties in the Rocky Mountain region that we plan to flood with CO_2: Bell Creek Field, Grieve Field, Hartzog Draw Field, and Cedar Creek Anticline. The Cedar Creek Anticline is a geological structure over 126 miles in length consisting of 10 different operating units. We have contracted to purchase CO_2 from the Lost Cabin gas plant in central Wyoming and completed construction of the first section of the Greencore Pipeline in late 2012 to deliver CO_2 from such gas plant to our Bell Creek Field. We currently expect to begin purchasing CO_2 from the Lost Cabin plant during the first quarter of 2013 and start injections at Bell Creek Field during the second quarter of 2013. Our Riley Ridge acquisitions in 2010 and 2011 and ExxonMobil CO_2 acquisition in 2012 provide us additional sources of CO_2 for our currently planned and future potential projects in the area.

Tertiary Oil Properties

Gulf Coast Region

CO_2 Sources and Pipelines

Jackson Dome. Our primary Gulf Coast CO_2 source, Jackson Dome, located near Jackson, Mississippi, was discovered during the 1970s while being explored for hydrocarbons. This significant and relatively pure source of CO_2 (98% CO_2) is, to our knowledge, the only significant deposit of CO_2 in the United States east of the Mississippi River, 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 also 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 and drilled numerous CO_2-producing wells, significantly increasing our estimated proved Gulf Coast CO_2 reserves from approximately 800 Bcf at the time of acquisition to approximately 6.1 Tcf as of December 31, 2012. The CO_2 reserve estimates are based on a gross working interest of the CO_2 reserves, of which our net revenue interest is approximately 4.8 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 our own tertiary recovery programs and for industrial users who are customers of Denbury and others, as we are responsible for distributing the entire CO_2 production stream.

In addition to the proved reserves, we estimate that we have 2.4 Tcf of probable CO_2 reserves at Jackson Dome, and significant other possible reserves. 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 (1) the original well is plugged; (2) they are located in fault blocks that are immediately adjacent to fault blocks with proved reserves; (3) 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 (4) they are reserves associated with increasing the ultimate recovery factor from our existing reservoirs with proved reserves. Our historically high drilling success rate, coupled with our seismic data across the undrilled structures, provide us with a reasonably high degree of certainty that additional CO_2 reserves will be developed.

Although our current proved 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 conducted several 3D seismic surveys in the area over the past several years, and anticipate drilling five development wells in 2013 that are intended to increase productive capacity, three of which could potentially add incremental CO_2 reserves. In addition to our drilling at Jackson Dome, we continue to expand our processing and dehydration capacities, and we continue to install pipelines and/or pumping stations necessary to transport the CO_2 through our controlled pipeline network. We expect our current proved reserves of CO_2, coupled with a risked drilling program at Jackson Dome and expected anthropogenic sources, to provide more than enough 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. Additionally, in the future, we believe that once a CO_2 flood reaches its productive economic limit, we could recycle a portion of the CO_2 that remains in that reservoir and utilize it in another tertiary flood.

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 currently have three CO_2 volumetric production payment contracts. Approximately 91% of our average daily CO_2 production in 2012 and 2011 and 87% in 2010 was used in our tertiary recovery operations on our own behalf and on behalf of other working interest owners and royalty owners in our enhanced recovery fields, with the balance delivered to third-party industrial users. During 2012, we sold an average of 92 MMcf/d of CO_2 to commercial users, and we used an average of 933 MMcf/d for our tertiary activities. We are continuing to increase our CO_2 production, which averaged 1,100 MMcf/d during the fourth quarter of 2012, a 7% increase over the fourth quarter of 2011.

Gulf Coast Anthropogenic CO_2 Sources. In addition to our natural source of CO_2, we are currently party to five long-term contracts to purchase man-made CO_2 from five plants that either exist, are currently under construction, or are planned, in the Gulf Coast region. In late 2012, we received first deliveries of anthropogenic CO_2 into the Gulf Coast pipeline system from an industrial facility in Port Arthur, Texas, and we anticipate taking deliveries from another existing plant in 2013 and a plant currently under construction in early 2014. We estimate these three sources will supply approximately 200 MMcf/d of CO_2 to our EOR operations, although under certain circumstances they could provide higher volumes. If the remaining two plants as to which we have long-term CO_2 purchase contracts also were to be built, we currently estimate our anthropogenic CO_2 sources could potentially provide us with aggregate CO_2 volumes of up to 600 MMcf/d. Construction of these two plants is considered probable, although is contingent on the satisfactory resolution of various matters, including financing. While both of these plants may not be constructed, other plants currently being planned could provide us additional anthropogenic CO_2. We are in ongoing discussions with, and/or have entered into contractual arrangements to purchase CO_2 from, several of these other potential sources.

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 and/or transport. In order to capture such volumes, we (or the plant owner) would need to install additional equipment, which includes, at a minimum, compression and dehydration facilities. Most of these existing plants emit relatively small volumes of CO_2, generally less than the proposed gasification plants, but such volumes may still be attractive if the source is located near CO_2 pipelines. The capture of CO_2 could also be influenced by potential federal legislation, which could impose economic penalties for the emission of CO_2. We believe that we are a likely purchaser of CO_2 captured in our areas of operation because of the scale of our tertiary operations, 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 acquired or constructed nearly 750 miles of CO_2 pipelines, which give us the ability to deliver CO_2 throughout the Gulf Coast. As of December 31, 2012, we have access to over 920 miles of CO_2 pipelines in the Gulf Coast region. In addition to the NEJD CO_2 pipeline, the major pipelines are the Free State Pipeline (90 miles), the Delta Pipeline (110 miles) and the Green Pipeline (325 miles).

Completion of the Green Pipeline facilitated the first CO_2 injection into the Hastings Field, located near Houston, Texas, in late 2010. 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, most of the CO_2 flowing in the Green Pipeline is delivered from the Jackson Dome area, but we recently began receiving anthropogenic CO_2 from a plant in Port Arthur, Texas, and will transport a third party's CO_2 for a fee to the sales point at Hastings Field. We expect the volume of anthropogenic CO_2 flowing through the Green Pipeline to increase in future years.

Tertiary Properties with Tertiary Production and Tertiary Reserves at December 31, 2012

Mature properties. Mature properties include several fields along our NEJD CO_2 pipeline and the Free State pipeline, which run through east Mississippi, southwest Mississippi and into Louisiana. This grouping includes some of our most mature CO_2 floods, including our initial CO_2 field, Little Creek, as well as several other areas (Brookhaven, Cranfield, Eucutta, Lockhart Crossing, Mallalieu, Martinville, McComb and Soso fields). These fields accounted for approximately 44% of our total 2012 CO_2 EOR production and 27% of our proved tertiary reserves. These fields have been producing for some time, and their production is generally on decline. Many of these fields contain multiple reservoirs that are amenable to CO_2 EOR. In 2013, we plan to invest approximately $90 million in our mature properties.

Most of the development work is complete in this area; however, there are some additional areas at McComb, Cranfield, Brookhaven and Little Creek that we currently plan to develop. EOR operations in Eucutta and Martinville fields were initiated in 2006 following completion of the Free State Pipeline, and the fields are mostly developed in the reservoir(s) under flood at the present time. In addition to the developed reservoirs, these fields have potential development targets in other vertically segregated reservoirs. 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 to maximize production.

Due to the lower viscosity of CO_2 when compared to oil, CO_2 will tend to follow the path of least resistance. This may result in high producing gas-oil ratios sooner than anticipated. In order to address this issue, we have experimented with various techniques such as cement squeezes (injection and producing wells), chemical squeezes, perforation design, mechanical isolation assemblies and operating pressure controls. We have also utilized water-alternating gas injections, where water is substituted for the CO_2 for a given volume and then CO_2 is injected behind the water. Each one of these processes has had some success and we plan to continue to utilize them in the future as appropriate.

From inception through December 31, 2012, we have recovered all our costs relating to our mature properties, and the excess net cash flow (revenue less operating expenses and capital expenditures, including the acquisition costs) from the mature properties was $1.7 billion. As of December 31, 2012, the estimated PV-10 Value of our mature properties was $1.9 billion.

Delhi Field. Delhi Field is located southwest of Tinsley Field and east of Monroe, Louisiana. During May 2006, we purchased Delhi for $50 million, plus an approximate 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 Field to Delhi Field. First tertiary production occurred at Delhi Field in March 2010. Current trend and performance data indicate that Delhi Field is acting as predicted and continues to provide a positive outlook for this field. Production from Delhi in the fourth quarter of 2012 averaged 5,237 Bbls/d, up from 3,778 Bbls/d in the year-ago period. In 2013, we plan to invest approximately $40 million to drill 15 wells and optimize existing development patterns at Delhi Field. Based on our current estimates, we expect the reversionary interest to come into effect some time in the latter part of 2013, which will reduce our net revenue interest in the field at that time.

From inception through December 31, 2012, 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 costs) from Delhi Field was $122 million. As of December 31, 2012, the estimated PV-10 Value of Delhi Field was $989.6 million.

Hastings Field. Hastings Field is located just south of Houston, Texas. We acquired a majority interest in this field in February 2009 for approximately $247 million. Due to the large vertical oil column that exists in the field, we are developing the Frio reservoir using dedicated CO_2 injection and producing wells for each of the major sand intervals. We initiated CO_2 injection in the West Hastings Unit during December 2010 upon completion of the construction of the Green Pipeline. We began producing oil from our EOR operations at Hastings Field in January 2012, and we booked proved tertiary reserves of 42.6 MMBbl for the West Hastings Unit in 2012. During the fourth quarter of 2012, tertiary production from Hastings Field averaged 3,409 Bbls/d, compared to zero in the year-ago period. In 2013, we plan to invest approximately $90 million to continue developing the West Hastings Unit, including the development of additional patterns and expansion of the processing facilities. Significant additional capital expenditures will be required over several years to fully develop the field.

From inception through December 31, 2012, 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 Hastings Field was $331 million. As of December 31, 2012, the estimated PV-10 Value of Hastings Field was $1.2 billion.

Heidelberg Field. In 2008, we began CO_2 injections at Heidelberg Field, which is located in Mississippi and consists of an East and West Unit. Construction of the CO_2 facility, connecting pipeline and well work commenced on the West Heidelberg Unit during 2008, with our first CO_2 injections beginning in December 2008. Our first tertiary oil production response occurred during May 2009. During 2010, we added injection patterns and expanded the central processing facility. Production from the West Unit began to decline in 2011 and we determined that CO_2 was not reaching all the targeted zones, broadly described as “conformance issues.” In 2011, we modified our development pattern to address the conformance issues by redirecting CO_2 into previously unswept intervals in the West Heidelberg Unit, and we believe this work has been successful. During the fourth quarter of 2012, tertiary production at Heidelberg Field averaged 3,930 Bbls/d, compared to 3,728 Bbls/d in the year-ago period. In 2012, we continued the development of our East Heidelberg Unit, which is larger and contains more oil in place than the West Heidelberg Unit, by initiating the second phase of the Eutaw development and the first phase of the Christmas development. In 2013, we plan to invest approximately $100 million to continue developing the East Heidelberg Unit, including an expansion of our development of the Eutaw and Christmas zones, and we plan to invest $20 million in the West Heidelberg Unit to optimize our development in the area.

From inception through December 31, 2012, we have recovered all our costs relating to the CO_2 flood at Heidelberg Field, and the excess net cash flow (revenue less operating expenses and capital expenditures, including the acquisition costs) from the field was $51 million. As of December 31, 2012, the estimated PV-10 Value of Heidelberg Field was $1.2 billion.

Oyster Bayou Field. Oyster Bayou Field, of which we acquired a majority interest in 2007, is located in southeast Texas on the east side of Galveston Bay. Oyster Bayou Field was unitized in the spring of 2010 and we began CO_2 injections there in June 2010. Oyster Bayou Field is somewhat unique when compared to our other CO_2 EOR projects because the field covers a relatively small area of 3,912 acres and was designed to be developed in essentially one stage. We commenced production from Oyster Bayou Field in December 2011 and booked initial proved tertiary reserves for the field of 14.1 MMBbl in 2012. During the fourth quarter of 2012, tertiary production at Oyster Bayou Field averaged 1,826 Bbls/d, compared to 18 Bbls/d in the year-ago period. In 2013, we plan to invest approximately $5 million to increase our CO_2 injection and water disposal capacity at Oyster Bayou Field.

From inception through December 31, 2012, 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 costs) from Oyster Bayou Field was $165 million. As of December 31, 2012, the estimated PV-10 Value of Oyster Bayou Field was $496.5 million.

Tinsley Field. Tinsley Field was acquired in January 2006, is located in 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 upon the completion of the 24-inch Delta Pipeline to Tinsley Field. We had our first tertiary oil production from Tinsley Field in April 2008. As of December 31, 2012, we have completed the development of the West and East Fault Blocks. In 2012, we installed and began injection into three patterns of the North Fault Block of Tinsley. We also installed trunklines and a test site to support future North Fault Block development. In 2013, we expect to invest approximately $40 million to continue our development of the North Fault Block at Tinsley Field. During the fourth quarter of 2012, the average tertiary oil production was 8,166 Bbls/d as compared to 6,338 Bbls/d in the year-ago period.

From inception through December 31, 2012, 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 $151 million. As of December 31, 2012, the estimated PV-10 Value of Tinsley Field was $1.1 billion.

Future Tertiary Properties with No Tertiary Production or Tertiary Reserves at December 31, 2012

Webster Field. We acquired our interest in Webster Field in November 2012 as part of the Bakken Exchange Transaction. The field is located in Texas, approximately eight miles northeast of our Hastings Field, which we are currently flooding with CO_2. The acquired Webster Field interests had estimated proved conventional reserves of approximately 3.7 MMBOE at December 31, 2012. In December 2012, conventional production at Webster Field averaged 1,104 BOE/d net to our acquired interest. Webster Field is geologically similar to our Hastings and Thompson fields, producing oil from the Frio zone at similar depths, and is believed to be an ideal candidate for a CO_2 flood. In 2013 we plan to invest approximately $20 million on conventional infill drilling opportunities and recompletions along with preliminary CO_2 flood scoping at Webster Field. We currently plan to commence CO_2 injections at Webster Field in 2015, with first tertiary production expected that same year.

Conroe Field. Conroe Field, our largest potential tertiary flood in the Gulf Coast region, is located north of Houston, Texas. We acquired a majority interest in this field in 2009 for approximately $271 million in cash and 11.6 million 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 12.5 MMBOE at December 31, 2012, nearly all of which are proved developed. During the fourth quarter of 2012, production at Conroe Field averaged 2,745 BOE/d net to our acquired interest, compared to 2,587 BOE/d in the year-ago period. Given the size of the Conroe Field of approximately 20,000 acres, the volume of CO_2 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 CO_2.

A pipeline must be constructed so that CO_2 can be delivered to Conroe Field. This pipeline, which is planned as an extension of our Green Pipeline, is preliminarily estimated to cover approximately 90 miles at a cost of $200 million to $240 million. With our acquisition of Webster Field in 2012, we deferred our construction plans for the Conroe pipeline by two years thus similarly deferring development plans for Conroe Field. We now plan to construct this pipeline in 2016 and to commence CO_2 injections at Conroe Field in 2017 with first tertiary production expected that same year. In 2013, we plan to determine the pipeline path, continue the acquisition of rights-of-way, and engineer and design the pipeline while refining and finalizing our CO_2 EOR plan for Conroe Field. In 2013 we also plan to invest $15 million on conventional infill drilling opportunities and recompletions at Conroe Field.

Thompson Field. We acquired our interest in Thompson Field in June 2012 for $366.2 million. The field is located in Texas, approximately 18 miles west of our Hastings Field. The acquired Thompson Field interests had estimated proved conventional reserves of approximately 16.7 MMBOE at December 31, 2012, of which approximately 55% are proved developed. In December 2012, conventional production at Thompson Field averaged 1,507 BOE/d net to our interest. Thompson Field is geologically similar to Hastings Field, producing oil from the Frio zone at similar depths; it is also expected to be an ideal candidate for a CO_2 flood. Under the terms of the Thompson Field acquisition agreement, after the initiation of CO_2 injection the seller will retain approximately a 5% gross revenue interest (less severance taxes) once average monthly oil production exceeds 3,000 Bbls/d. In 2013, we plan to invest $15 million on conventional infill drilling opportunities and recompletions at Thompson Field. We currently plan to commence CO_2 injections at Thompson Field in mid-2018, with first tertiary production expected in 2019.

Rocky Mountain Region

CO_2 Sources and Pipelines

LaBarge Field. LaBarge Field is located in southwestern Wyoming. The gas composition from LaBarge Field is approximately 65% CO_2, 20% natural gas, 5% hydrogen sulfide (H2S), less than one percent helium, and the remainder other gases.

We acquired an overriding royalty interest equivalent to an approximate one-third ownership interest in ExxonMobil's CO_2 reserves in LaBarge Field in southwestern Wyoming in December 2012 as part of the Bakken Exchange Transaction. Based on the current capacity of ExxonMobil's Shute Creek gas processing plant at LaBarge Field and subject to availability, we expect to receive up to approximately 115 MMcf/d of CO_2 from such plant. We will pay ExxonMobil a fee to process and deliver the CO_2, which will initially be used to flood our Bell Creek, Grieve and Hartzog Draw fields. As of December 31, 2012, our interest in LaBarge Field consisted of approximately 1.3 Tcf of proved CO_2 reserves.

The Riley Ridge Federal Unit is also located in southwestern Wyoming and will produce gas from LaBarge Field. We acquired interests in Riley Ridge in two phases. In 2010, we acquired a 42.5% non-operated working interest for $132.3 million. This initial purchase included a 42.5% interest in a gas plant under construction that will separate the helium and natural gas from the gas stream. In 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 consummation 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. We currently expect the gas plant to be operational in mid-2013 once all engineering safety systems are in place. We plan to invest approximately $40 million at Riley Ridge in 2013 to complete the initial phase of the facilities and drill one producing well and complete one injection well.

As of December 31, 2012, our interest in Riley Ridge and minor surrounding acreage contained net proved reserves of 416 Bcf (69 MMBOE) of natural gas and 2.2 Tcf of CO_2 reserves. The CO_2 reserve estimates are based on the gross working interest of the CO_2 reserves, in which our net revenue interest is approximately 1.6 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, 2012, we estimate that Riley Ridge contains proved helium reserves of 12.7 Bcf, which volume estimate is reduced to reflect the related fee we will remit to the U.S. government. In addition, we believe there is significant reserve potential in other acreage surrounding Riley Ridge in which we also own an interest.

The gas plant currently under construction at Riley Ridge will separate the natural gas and helium from the full well stream, and the remaining gases, including CO_2, will initially be reinjected into the producing formation until a planned CO_2 capture facility and pipeline can be built. We have initiated the engineering and design of the CO_2 capture facility, which is estimated to initially capture up to 130 MMcf/d of CO_2, and we currently plan to double this capacity within the next decade. We currently project that we will start to use CO_2 from Riley Ridge around 2017.

Other Rocky Mountain CO_2 Sources. We have ongoing discussions with, and are actively pursuing, several sources for CO_2 supply in the Rocky Mountain region. We have contracted to purchase CO_2 from the Lost Cabin plant in central Wyoming, which agreement will provide as much as 50 MMcf/d of CO_2 from the Lost Cabin plant. We have completed all necessary work to receive the CO_2 and expect first CO_2 deliveries from Lost Cabin in the first quarter of 2013.

In 2011, we entered into a long-term supply contract to purchase anthropogenic CO_2 from a proposed plant in southeastern Wyoming. We estimate the proposed plant could initially supply approximately 100 MMcf/d, and potentially up to 200 MMcf/d of CO_2 for our enhanced oil recovery operations in Wyoming and Montana. We would expect to begin taking delivery of CO_2 approximately four years following commencement of construction of this plant. 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 from proposed plants, 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 serve as our trunk-line in the Rocky Mountain region, eventually connecting our Lost Cabin, LaBarge and Riley Ridge CO_2 sources (see *Rocky Mountain region CO_2 Sources and Pipelines* above) to the Cedar Creek Anticline in eastern Montana, and may connect to other potential anthropogenic CO_2 sources in the region. The initial 232-mile section of the Greencore Pipeline begins at the Lost Cabin gas plant and terminates at our Bell Creek oil field in Montana. We completed construction of this section of the pipeline in late 2012 and expect to receive first CO_2 deliveries from the Lost Cabin gas plant in the first quarter of 2013. In 2013, we plan to build an interconnect between our Greencore Pipeline and an existing third-party CO_2 pipeline owned by another party in Wyoming. We plan to transport CO_2 from LaBarge Field to the Greencore Pipeline through this existing pipeline for use in planned CO_2 floods at Bell Creek and Hartzog Draw fields.

Future Tertiary Properties with No Tertiary Production or Tertiary Reserves at December 31, 2012

Bell Creek Field. Bell Creek Field is located in southeast Montana. We acquired our interest in Bell Creek through the Encore Merger. As of December 31, 2012, the majority of the work in this field has involved re-activating wells and injecting additional water into the reservoir to raise reservoir pressure in anticipation of future CO_2 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 CO_2 injections in Bell Creek Field in the first half of 2013 and anticipate first tertiary oil production in the second half of 2013. The producing reservoir in Bell Creek Field is a sandstone reservoir very similar to our Gulf Coast reservoirs. Conventional production, net to our interest, during the fourth quarter of 2012 averaged 781 Bbls/d, as compared to 840 Bbls/d in the year-ago period. In 2013, we plan to invest approximately $100 million to install compression equipment and facilities and continue the development of injection patterns at Bell Creek Field.

Hartzog Draw Field. We acquired our interest in Hartzog Draw Field in November 2012 as part of the Bakken Exchange Transaction. The field is located in the Powder River Basin of northeastern Wyoming, approximately 12 miles from our Greencore Pipeline. The acquired Hartzog Draw interests had estimated proved reserves of approximately 5.2 MMBOE at December 31, 2012, 1.9 MMBOE of which relate to the natural gas producing Big George coal zone. In December 2012, conventional production at Hartzog Draw Field averaged 2,444 BOE/d net to our acquired interest. The oil reservoir characteristics of Hartzog Draw Field make the field an ideal candidate for a CO_2 flood. In 2013, we plan to invest approximately $13 million on conventional infill drilling opportunities and recompletions at Hartzog Draw Field. We must obtain regulatory approval and construct a 12-mile CO_2 pipeline from our existing Greencore Pipeline to Hartzog Draw Field before we can commence an EOR flood. We anticipate that we will be able to commence CO_2 injections at Hartzog Draw Field in 2016 with first tertiary production expected that same year.

Cedar Creek Anticline. CCA is primarily located in Montana but covers such a large area (approximately 126 miles) that it also extends into North Dakota. CCA is a series of 10 producing oil units, each of which could be considered a field by itself. We acquired our initial 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 2012 from all of the units in CCA averaged 8,493 BOE/d, compared to 8,858 BOE/d in the year-ago period. The conventional proved reserves associated with CCA were 66.8 MMBbls of oil and 0.4 Bcf of gas as of December 31, 2012. In January 2013, we entered into a definitive agreement with a wholly-owned subsidiary of ConocoPhillips whereby we plan to add to our CCA assets through the purchase of

ConocoPhillips' assets in the field. See *2012 Business Developments – Pending Cedar Creek Anticline Acquisition* above and Note 2, *Acquisitions and Divestitures,* to the Consolidated Financial Statements for further discussion of this transaction and information as to other recent acquisitions and divestitures by Denbury. The Pending CCA Acquisition is expected to add approximately 42 MMBOE of incremental proved reserves at CCA; production associated with these assets averaged approximately 11,000 BOE/d during the fourth quarter of 2012.

CCA is located approximately 110 miles north of Bell Creek Field, and we expect to ultimately connect this field to our Greencore Pipeline. In 2013, we plan to invest approximately $115 million to improve waterfloods of CCA through well and facility work, recomplete existing wells, and develop plans for our planned future CO_2 flood of the field. We currently plan to commence first CO_2 injections into the field in 2017 with first tertiary production expected that same year.

Grieve Field. In May 2011, we 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 are overseeing design, construction and operations of the field. We completed the required three-mile CO_2 pipeline to deliver CO_2 from an existing CO_2 pipeline to the Grieve Field in December 2012, and are contracting for the construction of the CO_2 recycle facility. We estimate first CO_2 injection at Grieve Field in the first quarter of 2013 and first tertiary production late in 2014 or early in 2015.

Non-Tertiary Oil Properties

Our non-tertiary production in 2012 totaled 36,483 BOE/d, or 51% of total production. Excluding production from the non-core asset divestitures discussed above, our continuing non-tertiary production totaled 21,636 BOE/d or 38% of our continuing production in 2012. A substantial portion of this production is generated from fields we intend to flood with CO_2 in the future, and which are discussed above under *Tertiary Oil Properties – Gulf Coast Region – Future Tertiary Properties with No Tertiary Production or Tertiary Reserves at December 31, 2012* and *Tertiary Oil Properties – Rocky Mountain Region – Future Tertiary Properties with No Tertiary Production or Tertiary Reserves at December 31, 2012*.

Gulf Coast Region

Other Non-Tertiary Fields. We have been active in East Mississippi since Denbury was founded in 1990 and are the largest oil producer in the state. Conventional or non-tertiary production during the fourth quarter of 2012 averaged approximately 3,663 BOE/d from this area (6% of our total continuing production), and we had proved reserves of 11.1 MMBOE as of December 31, 2012 (3% of our Company total). Since we have generally owned these properties in East Mississippi longer than properties in our other regions, these East Mississippi properties tend to be more fully developed. In 2012, we completed the sale of certain non-core assets with proved reserves of 6.4 MMBOE primarily located in central and southern Mississippi and in southern Louisiana for $141.8 million.

Our largest field in the region is the Heidelberg Field located in Mississippi, which for the fourth quarter of 2012 produced an average of 1,947 BOE/d of conventional or non-tertiary production. This compares to 3,129 BOE/d in the year-ago period, with most of the decline in production due to the conversion of conventional areas of the field to a CO_2 flood and the decline in natural gas production in the Selma Chalk. 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 CO_2 EOR and are in the process of converting the East Heidelberg waterflood units to CO_2 EOR. Heidelberg Field 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 approximately 3,700 feet that is developed with horizontal wells and, prior to 2012, hydraulic fracturing. The Selma Chalk is estimated to contain 28.2 Bcf of proved natural gas reserves as of December 31, 2012. Natural gas production from the Selma Chalk was 10.5 MMcf/d during the fourth quarter of 2012, compared to 13.4 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.

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, 2012:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Gulf Coast region	247,841	211,655	371,655	36,569	619,496	248,224
Rocky Mountain region	275,449	225,863	345,567	133,000	621,016	358,863
Total	523,290	437,518	717,222	169,569	1,240,512	607,087

Our net undeveloped acreage that is subject to expiration over the next three years, if not renewed, is approximately 35% in 2013, 2% in 2014 and 4% in 2015.

Productive Wells

The following table sets forth our gross and net productive oil and natural gas wells as of December 31, 2012:

	Producing Oil Wells		Producing Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Operated wells:						
Gulf Coast region	1,315	1,231.6	190	174.1	1,505	1,405.7
Rocky Mountain region	880	750.0	3	2.4	883	752.4
Total	2,195	1,981.6	193	176.5	2,388	2,158.1
Non-operated wells:						
Gulf Coast region	38	1.3	—	—	38	1.3
Rocky Mountain region	48	9.5	308	155.5	356	165.0
Total	86	10.8	308	155.5	394	166.3
Total wells:						
Gulf Coast region	1,353	1,232.9	190	174.1	1,543	1,407.0
Rocky Mountain region	928	759.5	311	157.9	1,239	917.4
Total	2,281	1,992.4	501	332.0	2,782	2,324.4

Drilling Activity

The following table sets forth the results of our drilling activities over the last three years. As of December 31, 2012, we had 19 gross (13.3 net) wells in progress.

	Year Ended December 31,					
	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells: (1)						
Productive (2)	1	—	—	—	—	—
Non-productive (3)	1	—	1	0.7	—	—
Development wells: (1)						
Productive (2)	205	90.4	221	116.6	127	62.8
Non-productive (3)(4)	16	11.8	—	—	—	—
Total	223	102.2	222	117.3	127	62.8

(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 2012, 2011 and 2010, an additional 45, 46 and 41 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, 2012, 2011 and 2010:

	Year Ended December 31,		
	2012	2011	2010
Net sales volume:			
Gulf Coast region			
Oil (MBbls)	15,621	14,635	14,657
Natural gas (MMcf)	5,907	7,934	22,271
Total Gulf Coast region (MBOE)	16,606	15,957	18,369
Rocky Mountain region (1)			
Oil (MBbls)	8,841	7,534	7,212
Natural gas (MMcf)	4,747	2,849	6,220
Total Rocky Mountain region (MBOE)	9,632	8,009	8,249
Total Company (MBOE)	26,238	23,966	26,618
Average sales price:			
Gulf Coast region			
Oil (per Bbl)	$105.59	$105.23	$ 78.35
Natural gas (per Mcf)	2.79	4.31	4.56
Rocky Mountain region			
Oil (per Bbl)	$ 82.33	$ 89.93	$ 71.12
Natural gas (per Mcf)	3.38	6.12	4.90
Total Company			
Oil (per Bbl)	$ 97.18	$100.03	$ 75.97
Natural gas (per Mcf)	3.05	4.79	4.63
Average production cost (per BOE sold): (2)			
Gulf Coast region	$ 24.96	$ 24.51	$ 19.94
Rocky Mountain region	12.23	14.52	12.61
Total Company	20.29	21.17	17.67

(1) The year ended December 31, 2012 includes production of approximately 5.3 MMBOE from our Bakken area assets sold in the fourth quarter, and excludes production related to the Pending CCA Acquisition, which we currently expect to close near the end of the first quarter of 2013.

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

PRODUCTION AND UNIT PRICES

Further information regarding average production rates, unit sale prices and unit costs per BOE are set forth under Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations – 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 encumbrances, easements and restrictions which we do not believe are material to our operations.

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, 2012, 2011 and 2010, two purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company LLC (39%, 43% and 46% in 2012, 2011 and 2010, respectively) and Plains Marketing LP (17%, 16% and 14% in 2012, 2011 and 2010, respectively).

Our ability to market oil and natural gas depends on many factors beyond our control, including the extent of domestic production and imports of oil and gas, the proximity of our oil and natural gas production to pipelines, the available capacity in such pipelines, the demand for oil and natural gas, the effects of weather, and the effects of state and federal regulation. Our production in the Gulf Coast region is primarily from developed fields close to major pipelines or refineries and established infrastructure. Our production in the Rocky Mountain region is dependent on, among other factors, limited transportation options caused by oversubscribed pipelines and market centers that are distant from producing properties. As of December 31, 2012, 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

Over the past couple of years, the oil produced in the Gulf Coast region has benefited from strong pricing differentials in relation to NYMEX and, where possible, we have attached our production to Louisiana Light Sweet ("LLS") pricing. During 2012 and 2011, our light sweet oil production in this area, on average, sold for more than $11.50 per Bbl over NYMEX. The light and medium sour crude production has also benefited from the continued strength of other Gulf Coast grades relative to NYMEX, with production in 2012 selling at a premium to NYMEX of $6.69 per Bbl. Historically, LLS pricing and NYMEX pricing have been much closer together than the spread we have experienced over the last two years. The market dynamics of the region suggest the possibility of divergence from the current premiums currently being realized due to the influx of light sweet crude and condensate from producing regions outside of the Gulf Coast region by rail and publicly announced major pipeline projects. Our current markets, at various sales points along the Gulf Coast, have sufficient demand to accommodate our production, but there can be no assurance of future demand, and we are therefore monitoring the marketplace for opportunities to strategically enter into long-term marketing arrangements.

The marketing of our Rocky Mountain region oil production is dependent on transportation through local pipelines to market centers in Guernsey, Wyoming; Clearbrook, Minnesota; 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 increased stability of 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, 2012, the discount for our oil production in the Rocky Mountain region averaged $11.86 per Bbl, compared to $5.15 per Bbl during 2011. Excluding the Bakken area assets that we sold during the fourth quarter of 2012, our oil production in the Rocky Mountain region sold at a discount to NYMEX of $8.43 per Bbl during the year ended December 31, 2012.

Overall, during 2012, we sold approximately 40% of our crude oil at prices based on the LLS index price, approximately 22% at prices partially tied to the LLS index price, and the balance at prices based on various other indexes tied to NYMEX prices, primarily in the Rocky Mountain region. On a pro forma basis excluding Bakken area assets sold in 2012, we sold approximately 49% of our crude oil at prices based on the LLS index price and approximately 27% at prices partially tied to the LLS index price.

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, among other factors, limited transportation options that can affect our ability to find markets for it. We sell the majority of our natural gas on one-year contracts, with prices fluctuating month-to-month based on published pipeline indices and with slight premiums or discounts to the index. We currently receive near NYMEX or Henry Hub prices for most of our natural gas sales in Mississippi. For the year ended December 31, 2012, the amount received per Mcf for our Mississippi natural gas production was consistent with NYMEX prices. In the Texas Gulf Coast region, due primarily to its location, the price we received for the year ended December 31, 2012 averaged $0.08 per Mcf below 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. 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, 2012, we averaged $0.55 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.

Helium Marketing

We expect production to commence at Riley Ridge Field in mid-2013, after which we expect to 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 primary nature of our core assets (our tertiary operations) and our ownership of relatively uncommon significant natural sources of CO_2 in the Gulf Coast and Rocky Mountain regions, we believe that we are effective in competing in the market and have less competition than our peers in certain aspects of our business.

The demand for qualified and experienced field personnel to drill wells and conduct field operations and for geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages in such personnel. In recent years, the competition for qualified technical personnel has been extensive and our personnel costs have been escalating at a rate higher than general inflation. 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 other 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 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, although compliance and regulatory approval could cause delays or otherwise impede operations.

Regulation of Natural Gas and Oil Exploration and Production

Our operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for drilling wells; maintaining bonding requirements in order to drill or operate wells and regulating the location of wells; the method of drilling and casing wells; the surface use and restoration of properties upon which wells are drilled; the plugging and abandoning of wells; and the composition or disposal of chemicals and fluids used in connection with operations. Our operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling, spacing or proration units and the density of wells that may be drilled in those units, and the unitization or pooling of oil and gas properties. In addition, state conservation laws, which establish maximum rates of production from oil and gas wells, generally prohibit or restrict the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these 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 early 2012, the President signed the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011. This act, among other things, updates federal pipeline safety standards, increases penalties for violations of such standards, gives the Department of Transportation (the "DOT") authority for new damage prevention and incident notification, and directs the DOT to prescribe new minimum safety standards for CO_2 pipelines, which safety standards could affect our operations and the costs thereof. The DOT has not yet promulgated any such new minimum safety standards. In the future, Congress may create new incentives for alternative energy sources and may also consider legislation to reduce emissions of CO_2 or other greenhouse gases. If enacted, such legislation could (1) impose a tax or other economic penalty on the production of fossil fuels that, when used, ultimately release CO_2, (2) reduce the demand for, and uses of, oil, gas and other minerals, and/or (3) increase the costs incurred by us in our exploration and production activities. The Environmental Protection Agency ("EPA") has promulgated regulations requiring permitting for certain sources of greenhouse gas emissions, along with requirements for wells used for geologic sequestration. At the same time, legislation to reduce the emissions of CO_2 or other greenhouse gases could also create economic incentives for technologies and practices that reduce or avoid such emissions, including processes that sequester CO_2 in geologic formations such as depleted 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 CO_2, and the processing, handling and disposal of materials such as hydrocarbons and naturally occurring radioactive materials ("NORM") are subject to stringent regulation. We could incur significant costs, including cleanup costs resulting from a release of product, third-party claims for property damage and personal injuries, or penalties and other sanctions as a result of any violations or liabilities under environmental or other laws applicable to our operations. Changes in, or more stringent enforcement of, environmental laws and other laws applicable to our operations could also result in delays or additional operating costs and capital expenditures.

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

Management believes that we are in material 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 laws and regulations, and compliance therewith, could cause significant delays or otherwise impede operations, which may cause our expected production rates and cash flows to be less than anticipated.

Hydraulic Fracturing

We previously used a hydraulic fracturing process to stimulate production in our Bakken area and Selma Chalk properties. We sold our Bakken area properties during the fourth quarter of 2012 and have no current plans to hydraulically fracture any of our remaining oil and gas wells, including our Selma Chalk properties, during 2013. During 2012, we fracture stimulated 41 operated wells in the Bakken utilizing water-based fluids with no diesel fuel component. In these operations, we are cognizant of environmental laws and continually monitor all of our operations for possible environmental impact. During 2012, we derived in the range of 15% to 20% of our revenues from properties that have been fracture stimulated at some point in the useful life of the properties.

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

Internal Controls Over Reserve Estimates

Reserve information in this report is based on estimates prepared by DeGolyer and MacNaughton (“D&M”), an independent petroleum engineering consulting firm located in Dallas, Texas, utilizing data provided by our internal reserve engineering team and is the responsibility of management. We rely on D&M’s expertise to ensure that our reserve estimates are prepared in compliance with SEC rules and regulations and that appropriate geologic, petroleum engineering, and evaluation principles and techniques are applied in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)”. The person responsible for the preparation of the reserve report is a Senior Vice President at D&M; he is a Registered Professional Engineer in the State of Texas; he received a Bachelor of Science degree in Petroleum Engineering at Texas A&M University in 1974; and he has in excess of 38 years of experience in oil and gas reservoir studies and evaluations. Our Senior Vice President – Planning, Technology and Business Development is primarily responsible for overseeing the independent petroleum engineering firm during the process. Our Senior Vice President – Planning, Technology and Business Development has a Bachelor of Science degree in Petroleum Engineering from Louisiana State University and over 31 years of industry experience working with petroleum reserve estimates. D&M relies on various data provided by our internal reserve engineering team in preparing their reserve estimates, including such items as oil and natural gas prices, ownership interests, production information, operating costs, planned capital expenditures and other technical data. Our internal reserve engineering team consists of qualified petroleum engineers who maintain the Company’s internal evaluation of reserves and compare the Company’s information to the reserves prepared by D&M. Management is responsible for designing the internal control procedures used in the preparation of our oil and gas reserves, which include verification of data input into reserve forecasting and economics evaluation software, as well as multi-discipline management reviews. The internal reserve team reports directly to our Senior Vice President – Planning, Technology and Business Development. In addition, our Board of Directors' Reserves and Health, Safety and Environment ("HSE") Committee, on behalf of the Board of Directors, oversees the qualifications, independence, performance and hiring of our independent petroleum engineering firm and reviews the final report and subsequent reporting of our oil and natural gas reserve estimates. The Chairman of the Reserves and HSE Committee holds a Ph.D. in Chemical Engineering from the Massachusetts Institute of Technology and bachelor's degrees in Chemistry and Mathematics from Capital University in Ohio. He has 33 years of industry experience, with responsibilities including reserves preparation and approval.

Oil and Natural Gas Reserves Estimates

D&M prepared estimates of our net proved oil and natural gas reserves as of December 31, 2012, 2011 and 2010. See the summary of D&M's report as of December 31, 2012, included as an exhibit to this Form 10-K. These estimates of reserves were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices on the first day of each month within the 12-month period in accordance with rules and regulations of the SEC. These oil and natural gas reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties. During 2012, we provided oil and gas reserve estimates for 2011 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, 2011.

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, 2012, our estimated proved undeveloped reserves totaled approximately 162.7 MMBOE, or approximately 40% of our estimated total proved reserves, a decline of 38.5 MMBOE from December 31, 2011 levels. Our proved undeveloped oil reserves primarily relate to our CO_2 tertiary operations (72.8 MMBOE) and our proved undeveloped natural gas reserves are primarily located in our Riley Ridge Field (69.4 MMBOE) acquired in 2010 and 2011. Our December 31, 2012 proved undeveloped reserves also include 10.5 MMBOE of proved undeveloped reserves at our CCA fields acquired in 2010 and 7.4 MMBOE of proved undeveloped reserves we acquired at Thompson Field during 2012. We consider the CO_2 tertiary proved undeveloped reserves to be lower risk than other proved undeveloped reserves that require drilling at locations offsetting existing production, because all of these proved undeveloped reserves are associated with tertiary recovery operations in fields and reservoirs that historically produced substantial volumes of oil under primary production.

During 2012, we spent approximately $875 million to convert 40.5 MMBOE of proved undeveloped reserves to proved developed reserves. Proved undeveloped reserves were converted primarily through the expansion of our tertiary floods (25.0 MMBOE) and through additional drilling in the Bakken. During 2012, proved undeveloped reserve additions of 89.1 MMBOE, primarily related to the initial recognition of reserves associated with new tertiary floods (62.6 MMBOE) and the acquisition of Thompson Field (7.4 MMBOE), were partially offset by the decrease in proved undeveloped reserves resulting from the sale of our Bakken area assets (73.5 MMBOE).

As of December 31, 2012, 16.6 MMBOE of our total proved undeveloped reserves are not scheduled to be developed within five years of initial booking, all of which are part of CO_2 EOR projects. We believe these reserves satisfy the conditions to be included as proved reserves because (1) we have established and continue to follow the previously adopted development plan for each of these projects; (2) we have significant ongoing development activities in each of these CO_2 EOR projects and (3) we have an historical record of completing the development of comparable long-term projects.

	December 31,		
	2012	2011	2010
Estimated proved reserves (1)			
Oil (MBbls)	329,124	357,733	338,276
Natural gas (MMcf)	481,641	625,208	357,893
Oil equivalent (MBOE)	409,398	461,934	397,925
Reserve volumes categories			
Proved developed producing:			
Oil (MBbls)	208,745	189,904	186,705
Natural gas (MMcf)	60,832	116,562	104,050
Oil equivalent (MBOE)	218,884	209,331	204,047
Proved developed non-producing:			
Oil (MBbls)	27,264	49,837	32,372
Natural gas (MMcf)	3,359	9,408	6,466
Oil equivalent (MBOE)	27,824	51,405	33,450
Proved undeveloped:			
Oil (MBbls)	93,115	117,992	119,199
Natural gas (MMcf)	417,450	499,238	247,377
Oil equivalent (MBOE)	162,690	201,198	160,428
Percentage of total MBOE:			
Proved developed producing	53%	45%	51%
Proved developed non-producing	7%	11%	9%
Proved undeveloped	40%	44%	40%
Representative oil and natural gas prices: (2)			
Oil – NYMEX	$ 94.71	$ 96.19	$ 79.43
Natural gas – Henry Hub	2.85	4.16	4.40
Present values (thousands): (3)			
Discounted estimated future net cash flow before income taxes (PV-10 Value) (4)	$9,909,592	$10,559,139	$7,292,344
Standardized measure of discounted estimated future net cash flow after income taxes ("Standardized Measure")	$6,414,380	$ 7,007,605	$4,917,927

(1) Estimated proved reserves as of December 31, 2012 reflect the sale of reserves associated with our Bakken area assets sold in 2012 (approximately 109 MMBOE). Year-end 2012 reserves reflect CCA reserves acquired in 2010 as part of the Encore Merger, but do not include reserves of approximately 42 MMBOE related to the Pending CCA Acquisition, which we currently expect to close near the end of first quarter of 2013.

(2) 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 we receive. 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.

(3) 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.

(4) 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 $3,495,212 at December 31, 2012, $3,551,534 at December 31, 2011, and $2,374,417 at December 31, 2010. 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 14, *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 14, *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, 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 between year-end 2011 and year-end 2012, with NYMEX oil prices per Bbl decreasing 7%, and NYMEX natural gas prices per MMBtu increasing by 12%. 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 2012 production and 80% of our December 31, 2012 proved reserves, with oil being an even larger percentage of our current production and future potential reserves and projects due to our primary 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;
- storage levels of oil and natural gas;
- weather conditions, including hurricanes and tropical storms in and around the Gulf of Mexico that can damage oil and natural gas facilities and delivery systems and disrupt operations, and winter conditions and forest fires in the Rocky Mountains that can delay or impede operations;
- 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 five years oil prices have fluctuated significantly, reaching record highs of approximately $145 per Bbl in July 2008, declining precipitously during the last half of 2008, and ending that year at a NYMEX price of $44.60 per Bbl. Oil prices then reversed course, generally increasing through the past several years, ending 2011 at a NYMEX price of $98.83 per Bbl and ending 2012 at a NYMEX price of $91.82 per Bbl. Due to the volatility of oil prices, oil prices could decline to a level that makes our tertiary projects uneconomical. 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, both of which could have a material adverse effect on our operations. We may also be required to reduce our capital expenditures in the event of reduced commodity prices to reflect the reduced cash flow, which could reduce or eliminate our growth. We have a practice of hedging approximately 15 to 24 months (from the current quarter) of forecasted 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 21, 2013, we have oil commodity derivative contracts in place covering approximately 55,000 Bbls/d during 2013 and 50,000 Bbls/d during 2014. 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 point (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.

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, among other factors, the quality of the crude oil we sell, the location of our crude oil production and the related markets to which we sell, variations in prices paid based upon different indices used, and the pricing contracts and indices at which we sell production. Our NYMEX differentials on a field-by-field basis over the last few years have ranged from approximately $25 per Bbl above NYMEX to approximately $25 per Bbl below NYMEX. On a corporate-wide basis, our NYMEX differentials over the last few years have ranged from approximately $9 per Bbl above NYMEX oil prices to approximately $4 per Bbl below NYMEX oil prices. These variances have been due to various factors and are difficult to forecast or anticipate, but they have a direct impact on the net oil price we receive.

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 $4.40 per MMBtu during 2010, $4.03 per MMBtu during 2011, and $2.82 per MMBtu during 2012, and ended 2012 at $3.35 per MMBtu. As of February 21, 2013, we do not have any natural gas commodity derivative contracts in place.

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

Our long-term growth strategy is focused on our CO_2 tertiary recovery operations. The crude oil production from our tertiary recovery projects depends on having access to sufficient amounts of CO_2. Our ability to produce this oil would be hindered if our supply of CO_2 were limited due to problems with our current CO_2 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 CO_2 and inject adequate amounts of CO_2 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 CO_2 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 CO_2 pipelines could be delayed by difficulties in obtaining pipeline rights-of-way, 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 CO_2 to our oil fields at a cost that is economically viable. Our ongoing construction of CO_2 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 natural gas 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 laws, 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 CO_2 pipeline construction schedule and initiation of operations of our pipelines, and/or increase the costs of constructing our 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 21, 2013, we had outstanding $2.9 billion (principal amount) of subordinated notes at interest rates ranging from 4.625% to 9.75% at a weighted average interest rate of 6.61% and no amounts outstanding under our bank credit facility. We currently have a borrowing base of $1.6 billion under our bank credit facility, and at February 21, 2013, nearly all of this amount was available on such facility. The next regularly scheduled semiannual redetermination of the borrowing base for our bank credit facility will be in May 2013. 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, among other things, 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; 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 counterparty 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 Item 7. *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 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 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 more costly 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; 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 and forest fires 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 CO_2 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 CO_2 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, and certain operations may be practical only 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 can slow down our operations, cause delays and 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 in such personnel. In recent years, the competition for qualified technical personnel has been extensive and our personnel costs have been escalating at a rate higher than general inflation. 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. 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.

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

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

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

Numerous legislative and regulatory proposals affecting the oil and gas industry have been introduced, are anticipated to be introduced or are otherwise under consideration by Congress and various federal agencies. Among these proposals are: (1) climate change/carbon tax legislation introduced in Congress and EPA regulations to reduce greenhouse gas emissions, including an EPA proposal to apply New Source Performance Standards for petroleum refineries expected in 2013; (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 deductions for intangible drilling and development costs and 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 previously considered by Congress (but not adopted) that would subject the process of hydraulic fracturing to federal regulation under the Safe Drinking Water Act and new or anticipated Department of Interior 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 Department of Transportation to prescribe minimum safety standards for CO_2 pipelines, any of which could affect our operations, and the costs thereof. Generally, any 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. However, until such legislation or regulations are enacted or adopted into law and implemented, it is not possible to gauge their impact on our future operations or our results of operations and financial condition.

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

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

The recent adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to hedge risks associated with our business.

The Dodd-Frank Act requires the Commodities Futures Trading Commission, and the SEC to promulgate rules and regulations establishing federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. These new rules and regulations could significantly increase the cost or decrease the liquidity of energy-related derivatives we use to hedge against commodity price fluctuations. Although we believe the derivative contracts that we enter into should not be materially impacted by these new statutory and regulatory requirements, because derivatives regulations have not been finalized, final regulations could negatively affect to our detriment the economics and terms of derivative instruments available from counterparties in the marketplace.

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, 2012, two purchasers individually accounted for 10% or more of our oil and natural gas revenues and, in the aggregate, for 56% of such revenues. The loss of a large single purchaser could 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 first-day-of-the-month average oil and natural gas prices for the 12-month period preceding the date of the 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 used in the estimate.

As of December 31, 2012, approximately 40% 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 these expenditures and operations may not occur.

Significant acquisitions or other transactions could require substantial 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 from that of our existing properties.

Our results of operations could be negatively affected as a result of goodwill impairments.

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the acquisition of a business. At December 31, 2012, the Company's goodwill balance totaled $1.3 billion and represented approximately 11.5% of our total assets. Goodwill is not amortized; rather it is tested for impairment annually during the fourth quarter and when facts or circumstances indicate that the carrying value of the Company's goodwill may be impaired, requiring an estimate of the fair values of the reporting unit's assets and liabilities. An impairment of goodwill could significantly reduce earnings during the period in which the impairment occurs and would result in a corresponding reduction to goodwill and equity. See Item 7 – *Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies and Estimates – Impairment Assessment of Goodwill.*

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

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

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

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

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.

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 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.

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 January 31, 2013, 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 1,643. On February 27, 2013, the last reported sale price of Denbury's common stock, as reported on the NYSE, was $17.99 per share.

	2012		2011	
	High	Low	High	Low
First Quarter	$20.91	$16.29	$24.56	$18.45
Second Quarter	19.50	13.46	24.86	18.70
Third Quarter	17.65	13.74	20.85	11.50
Fourth Quarter	16.76	14.32	17.45	10.86

We have never paid any dividends on our common stock. Also, our bank credit facility limits the aggregate amount of (i) dividends we can pay on our common stock and (ii) our common stock we can repurchase. Under our bank credit facility, we had $679.0 million available as of February 21, 2013 that can be used to pay dividends or repurchase shares of Denbury's common stock. No unregistered securities were sold by the Company during 2012.

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	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in millions)(1)
October 2012	2,138,550	$ 16.35	2,133,910	$228.8
November 2012	6,052,120	15.03	6,018,276	409.5
December 2012	6,340,742	15.83	6,332,387	309.3 (2)
Total	14,531,412	15.57	14,484,573	309.3

(1) In October 2011, the Company's Board of Directors approved a common stock repurchase program for up to $500 million of Denbury's common stock, which was increased by an additional $271.2 million in early November 2012.

(2) Amounts shown do not give effect to the repurchase of an additional 3.5 million shares of Denbury common stock from January 1, 2013 through February 21, 2013 under the share repurchase program for $59.1 million, or $16.73 per share.

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, 2012, we repurchased 31,090,618 shares of Denbury common stock (approximately 7.7% of our outstanding shares of common stock at September 30, 2011) for $461.9 million, or $14.86 per share. The program was increased to $771.2 million in 2012, 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.

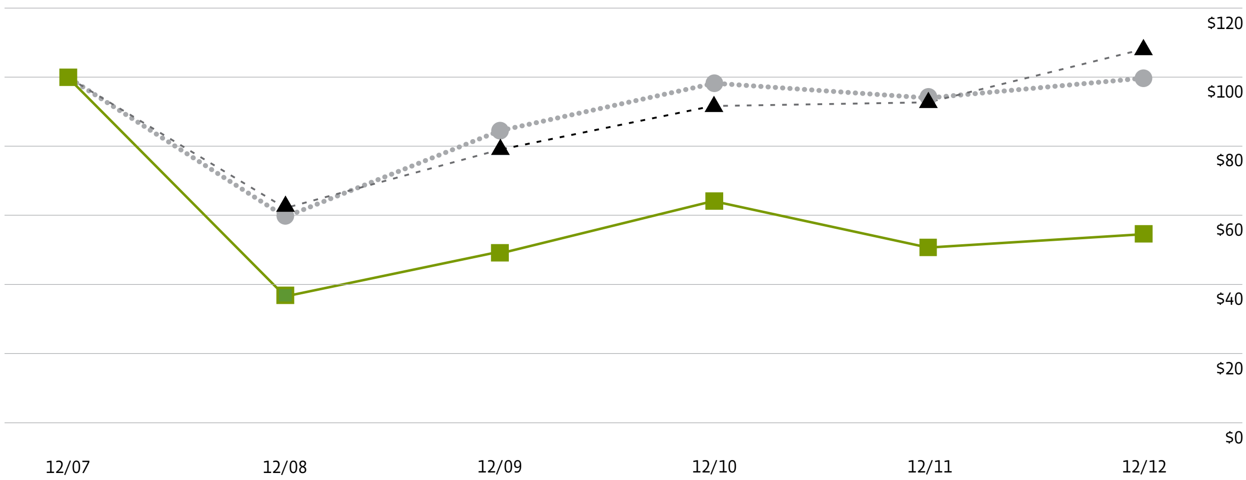
All other repurchases of our common stock during the fourth quarter of 2012 were made in connection with delivery by our employees of shares to us to satisfy their tax withholding requirements related to the vesting of restricted shares and the exercise of stock appreciation rights.

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, 2012, 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, 2007 to December 31, 2012.

COMPARISON OF 5-YEAR CUMULATIVE TOTAL RETURN



	December 31,					
	2007	2008	2009	2010	2011	2012
Denbury Resources Inc.	$100.00	$36.71	$ 49.75	$ 64.17	$50.76	$ 54.45
S&P 500	100.00	63.00	79.67	91.67	93.61	108.59
Dow Jones US Exploration and Production	100.00	59.88	84.17	98.26	94.14	99.62

Item 6. Selected Financial Data

In thousands, except per share data or otherwise noted	Year Ended December 31,				
	2012	2011	2010 [1]	2009	2008
Consolidated Statements of Operations data:					
Revenues and other income:					
Oil, natural gas, and related product sales	$ 2,409,867	$ 2,269,151	$1,793,292	$ 866,709	$1,347,010
Other	46,605	40,173	128,499	22,441	24,046
Total revenues and other income	$ 2,456,472	$ 2,309,324	$1,921,791	$ 889,150	$1,371,056
Net income (loss) attributable to Denbury stockholders [2]	525,360	573,333	271,723	(75,156)	388,396
Net income (loss) per common share:					
Basic	1.36	1.45	0.73	(0.30)	1.59
Diluted	1.35	1.43	0.72	(0.30)	1.54
Weighted average number of common shares outstanding:					
Basic	385,205	396,023	370,876	246,917	243,935
Diluted	388,938	400,958	376,255	246,917	252,530
Consolidated Statements of Cash Flows data:					
Cash provided by (used by):					
Operating activities	$ 1,410,891	$ 1,204,814	$ 855,811	$ 530,599	$ 774,519
Investing activities	(1,376,841)	(1,605,958)	(354,780)	(969,714)	(994,659)
Financing activities	45,768	37,968	(139,753)	442,637	177,102
Production (average daily):					
Oil (Bbls)	66,837	60,736	59,918	36,951	31,436
Natural gas (Mcf)	29,109	29,542	78,057	68,086	89,442
BOE (6:1)	71,689	65,660	72,927	48,299	46,343
Unit sales prices – excluding impact of derivative settlements:					
Oil (per Bbl)	$ 97.18	$ 100.03	$ 75.97	$ 57.75	$ 92.73
Natural gas (per Mcf)	3.05	4.79	4.63	3.54	8.56
Unit sales prices – including impact of derivative settlements:					
Oil (per Bbl)	$ 96.77	$ 98.90	$ 71.69	$ 68.63	$ 90.04
Natural gas (per Mcf)	5.67	7.34	6.45	3.54	7.74
Costs per BOE:					
Lease operating expenses	$ 20.29	$ 21.17	$ 17.67	$ 17.85	$ 17.71
Taxes other than income	6.10	6.16	4.53	2.45	3.06
General and administrative expenses	5.49	5.24	5.04	5.77	3.36
Depletion, depreciation and amortization	19.34	17.07	16.32	13.52	13.08
Proved oil and natural gas reserves: [3]					
Oil (MBbls)	329,124	357,733	338,276	192,879	179,126
Natural gas (MMcf)	481,641	625,208	357,893	87,975	427,955
MBOE (6:1)	409,398	461,934	397,925	207,542	250,452
Proved carbon dioxide reserves:					
Gulf Coast region (MMcf) [4]	6,073,175	6,685,412	7,085,131	6,302,836	5,612,167
Rocky Mountain region (MMcf) [5]	3,495,534	2,195,534	2,189,756	—	—
Proved helium reserves associated with Denbury's production rights: [6]					
Rocky Mountain region (MMcf)	12,712	12,004	7,159	—	—
Consolidated Balance Sheets data:					
Total assets	$11,139,342	$10,184,424	$9,065,063	$4,269,978	$3,589,674
Total long-term liabilities	5,408,032	4,716,659	4,105,011	1,903,951	1,363,539
Stockholders' equity	5,114,889	4,806,498	4,380,707	1,972,237	1,840,068

(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 2009, we had a pretax charge of $236.2 million associated with our commodity derivative contracts.

(3) Estimated proved reserves as of December 31, 2012 reflect the disposition of reserves associated with our Bakken area assets sold in late 2012 (approximately 109 MMBOE). Year-end 2012 reserves reflect CCA reserves acquired in 2010 as part of the Encore Merger, but do not include estimated reserves of approximately 42 MMBOE related to the Pending CCA Acquisition, which we currently expect to close near the end of first quarter of 2013.

(4) Proved CO_2 reserves in the Gulf Coast region consist of reserves from our reservoirs at Jackson Dome and are presented on a gross or 8/8ths working interest basis, of which our net revenue interest was approximately 4.8 Tcf, 5.3 Tcf, 5.6 Tcf, 5.0 Tcf and 4.5 Tcf at December 31, 2012, 2011, 2010, 2009 and 2008, respectively, and include reserves dedicated to volumetric production payments of 57.1 Bcf, 84.7 Bcf, 100.2 Bcf, 127.1 Bcf and 153.8 Bcf at December 31, 2012, 2011, 2010, 2009 and 2008, respectively. (See Note 15, *Supplemental CO_2 and Helium Disclosures (Unaudited),* to the Consolidated Financial Statements.)

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

(6) Reserves associated with helium production rights include helium reserves located in the acreage in the Rocky Mountain region for which we have the 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 estimate of helium reserves is reduced to reflect the related fee we will remit to the U.S. government.

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 Form 10-K, along with *Forward-Looking Information* at the end of this section for information on the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

OVERVIEW

Our primary focus is on enhanced oil recovery utilizing CO_2 and our operations are focused in two key operating areas: the Gulf Coast region and Rocky Mountain region. We are the largest combined oil and natural gas producer in both Mississippi and Montana, and we own the largest reserves of CO_2 used for tertiary oil recovery east of the Mississippi River. 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 relating to tertiary recovery operations.

Strategic and Value-Driven Transactions

Over the last year, we completed or entered into agreements on several strategic and tax efficient property transactions which not only add value, but as importantly, make us a nearly pure CO_2 EOR company. These asset transactions, which included both acquisitions and dispositions, aggregated (or upon completion will aggregate) over $4 billion in value, and (1) resulted in an increase in our unproven potential reserves, which we believe provides us a better opportunity to achieve a higher return due to the nature of the acquired properties compared to the sold properties, (2) nearly replaced the production of the sold assets with that from the acquired or to-be-acquired assets, (3) exchanged proved reserves with a high proved undeveloped component for reserves that are nearly all proved developed, which significantly increases our current free cash flow, (4) increased our Rocky Mountain CO_2 reserves by 1.3 Tcf and up to 115 MMcf/d of deliverability, and (5) positioned us to execute on our long-term strategy which we expect will increase shareholder value for many years to come. A summary of these transactions follows, with more detail on each significant transaction discussed below in this overview section.

- Bakken Exchange Transaction – Divested our Bakken area assets, which were all non-tertiary, at an estimated value of approximately $2.0 billion, in exchange for interests in two future potential tertiary oil fields, a new Rocky Mountain region CO_2 source and $1.3 billion of cash.
- Pending Cedar Creek Anticline Acquisition – Entered into an agreement in early 2013 to purchase additional interests in the Cedar Creek Anticline ("CCA") in Montana and North Dakota, an area with future potential tertiary oil upside, for $1.05 billion, which will be funded with a portion of the cash proceeds from the Bakken Exchange Transaction. We expect to complete the Pending CCA Acquisition near the end of the first quarter of 2013.

In two separate transactions earlier in 2012, which were also structured as like-kind exchanges for federal income tax purposes, we completed the following:

- Acquisition of Thompson Field – Acquired a nearly 100% working interest and 84.7% net revenue interest in the Thompson Field in south Texas, a future potential tertiary oil field approximately 18 miles from our current EOR flood at Hastings Field, for $366.2 million.
- Sale of Non-core Assets – Sold our interests in non-core oil and natural gas fields in the Paradox Basin of Utah and in the Gulf Coast region for $68.5 million and $141.8 million, respectively.

Bakken Exchange Transaction. In late 2012, we closed a sale and exchange transaction with Exxon Mobil Corporation and its wholly-owned subsidiary XTO Energy Inc. (collectively, "ExxonMobil") under which we sold to ExxonMobil our Bakken area assets in North Dakota and Montana in exchange for $1.3 billion in cash (after preliminary closing adjustments) and EOR-related assets (the "Bakken Exchange Transaction"). By exchanging these non-tertiary Bakken area assets for EOR fields and CO_2 assets, we are able to more purely focus our attention on tertiary recovery operations. These acquired assets include:

- operating interests in the Webster Field, a planned future tertiary field located in southeastern Texas, made up of a nearly 100% working interest and nearly 80% net revenue interest. The field is located approximately eight miles from Denbury's Hastings Field which is currently being flooded with CO_2, and which is the current terminus of the Green Pipeline which transports CO_2 from natural sources in the Jackson Dome area of Mississippi. Webster Field is similar to Hastings Field, producing oil from the Frio zone at similar depths, and is also expected to be an ideal candidate for a CO_2 flood;
- operating interests in the Hartzog Draw Field, a planned future tertiary field, located in Wyoming, consisting of an 83% working interest and 71% net revenue interest in the oil producing Shannon Sandstone zone, and a 67% working interest and 53% net revenue interest in the natural gas producing Big George Coal zone. Hartzog Draw Field is located approximately 12 miles from the recently completed initial segment of our Greencore Pipeline and is expected to be an ideal candidate for a CO_2 flood; and
- an overriding royalty interest equivalent to an approximate one-third ownership interest in ExxonMobil's CO_2 reserves in LaBarge Field in Wyoming with an estimated 1.3 Tcf of proved reserves and up to 115 MMcf/d of deliverability.

The proved reserves acquired at Webster and Hartzog Draw fields total approximately 9 MMBOE at December 31, 2012. We did not record a gain or loss on the Bakken Exchange Transaction in accordance with the full cost method of accounting. The Bakken area assets had approximately 109 MMBOE of proved reserves at the time of sale, of which approximately 66% were undeveloped with an estimated future development cost of more than $1.7 billion. A total of $1.05 billion of the cash proceeds from the Bakken Exchange Transaction were placed into a qualifying trust account with a third party and will be used to fund the pending CCA acquisition discussed below, as a like-kind exchange for federal income tax purposes.

Pending Cedar Creek Anticline Acquisition. On January 14, 2013, we entered into an agreement to acquire producing assets in the CCA of Montana and North Dakota from a wholly-owned subsidiary of ConocoPhillips for $1.05 billion in cash (the "Pending CCA Acquisition"), before standard closing adjustments primarily for revenues and costs of the properties to be purchased from the January 1, 2013 effective date to the closing date. The assets we plan to purchase from ConocoPhillips include both additional interests in certain of our existing operated fields in CCA as well as operating interests in other CCA fields. We currently estimate on a preliminary basis that, as of December 31, 2012, the proved conventional (non-tertiary) reserves associated with the acquired assets, net to our acquired interests, were approximately 42 MMBOE. We expect the Pending CCA Acquisition to close near the end of the first quarter of 2013, and we plan to fund this acquisition with a portion of the cash proceeds from the Bakken Exchange Transaction (see discussion above), of which $1.05 billion was placed in qualifying trust accounts in order to qualify this acquisition for like-kind-exchange treatment for federal income tax purposes.

Acquisition of Thompson Field. In June 2012, we acquired operating interests in Thompson Field for $366.2 million after preliminary closing adjustments, which added approximately 900 BOE/d to our production in 2012. The field is located approximately 18 miles west of Denbury's Hastings Field which is currently being flooded with CO_2, and which is the current terminus of the Green Pipeline which transports CO_2 from natural sources in the Jackson Dome area of Mississippi. Thompson Field is similar to Hastings Field, producing oil from the Frio zone at similar depths, and is a planned future tertiary field. We funded the purchase principally with cash proceeds from property sales earlier in 2012 and the remainder from borrowings under our bank credit facility.

Sale of Non-Core Assets. On January 19, 2012, we sold our investment in Vanguard Natural Resources LLC common units for cash consideration of $83.5 million, net of related transaction fees. On February 29, 2012, we completed the sale of certain Gulf Coast assets primarily located in central and southern Mississippi and in southern Louisiana for $155.0 million, realizing net proceeds of $141.8 million after final closing adjustments. On April 9, 2012, we completed the sale of certain non-operated assets in the Paradox Basin of Utah for $75.0 million, realizing net proceeds of $68.5 million after final closing adjustments.

2012 Highlights

2012 Operating Highlights. Our net income was $525.4 million, or $1.35 per diluted common share, during 2012, compared to net income of $573.3 million, or $1.43 per diluted common share, during 2011. Although we had a $140.7 million increase in oil and natural gas revenues in 2012 compared to 2011, which was primarily driven by higher production, this increase in revenues was more than offset by increases in other expenses, such as a $63.2 million non-cash change in the fair value of our commodity derivative contracts in 2012 compared to 2011, and an increase of $98.3 million in depletion, depreciation and amortization and $25.0 million in lease operating expenses, largely driven by increased production. Our cash flow from operations was $1.4 billion in 2012, compared to $1.2 billion in 2011, with the increase primarily due to the increase in oil revenues and changes in working capital items.

During 2012, our oil and natural gas production, which was 93% oil (as was the case in 2011), averaged 71,689 BOE/d, compared to 65,660 BOE/d produced during 2011. The increase in production is primarily attributable to record production from our tertiary oil properties (an increase of 4,247 BOE/d, or 14% from 2011) and production from our recently disposed Bakken area assets (an increase of 5,055 BOE/d, or 54% from 2011 levels). See *Results of Operations – Operating Results – Production* for more information.

The average oil price we realized during 2012, excluding the impact of derivative contracts, was $97.18 per barrel, or about 3% lower than prices realized during 2011. This decrease was due primarily to a decrease in the prices we receive relative to NYMEX oil prices, which we refer to as our NYMEX price differential. Our Gulf Coast region oil prices received in 2012 continued to be favorably impacted by a positive NYMEX price differential, as a large portion of that crude oil is sold under Louisiana Light Sweet ("LLS") pricing, which has maintained a price higher than NYMEX throughout the last two years; however, some of that benefit was offset by wider negative NYMEX price differentials in the Rocky Mountain region during 2012. See *Results of Operations – Operating Results – Oil and Natural Gas Revenues* below for more information.

Proved Oil and Natural Gas Reserves. Our estimated proved oil and gas reserves were 409.4 MMBOE as of December 31, 2012, as compared to 461.9 MMBOE at December 31, 2011. We added 114.2 MMBOE of estimated proved reserves during 2012, including tertiary reserves of 69.5 MMBbls, primarily at Hastings and Oyster Bayou fields based on these fields' responses to CO_2 injections, 25.9 MMBOE from the acquisition of interests in the Thompson, Webster and Hartzog Draw fields, and 11.5 MMBOE from our Bakken area assets prior to their sale in the fourth quarter of 2012. These increases were offset by the disposition of 123.9 MMBOE of reserves as a result of sales of our Bakken area assets, non-core assets in the Gulf Coast region and the Paradox Basin of Utah.

2013 Debt Issuance and Tender Offers

On February 5, 2013, we issued $1.2 billion of 4⅝% Senior Subordinated Notes due July 2023 (the "2023 Notes"). The net proceeds from this transaction of $1.18 billion were used to retire a portion of our senior subordinated notes and to pay down amounts outstanding on the Company's bank credit facility. As part of this refinancing, we (1) completed cash tender offers for our 9¾% Senior Subordinated Notes due 2016 (the "9¾% Notes") and our 9½% Senior Subordinated Notes due 2016 (the "9½% Notes"), (2) purchased a total of $378.4 million principal amount of outstanding notes in February 2013, and (3) subsequently called the 9¾% Notes for redemption effective on March 7, 2013. Beginning May 1, 2013, the remaining $38.2 million of 9½% Notes become redeemable at 104.75% of par.

CAPITAL RESOURCES AND LIQUIDITY

Overview. During the last year, we have completed or entered into agreements for several significant transactions (discussed above), with the purchase transactions funded with a portion of the cash proceeds from asset sales, resulting in a slight net increase in our cash or capital resources. We also purchased $461.9 million of our common stock between early October 2011 and December 31, 2012, funded by planned reduced capital expenditures in 2012 (i.e. cash flow), net cash from the transactions and bank debt (see stock purchase detail below). In early 2013, we refinanced two of our high-rate subordinated notes with ten-year notes carrying an interest rate of 4⅝%, lowering our interest expense and reducing, with a portion of the proceeds of our newest notes offering, our outstanding bank borrowings. As a result of these transactions, our current debt to cash flow is slightly higher than normal. Even so, we are comfortable that we will have more than adequate capital resources and liquidity for the foreseeable future because (i) we have refinanced our bank debt with low-cost subordinated debt, leaving significant borrowing capacity on our bank line; (ii) we have extended our oil hedges by about six months, hedging a substantial portion of our forecasted proven oil production for two years with a floor price of $80, (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); (iii) we expect to fund our projected capital expenditures for the next few years with cash flow from operations, which means that our expected growth in production and cash flow will gradually reduce our leverage (assuming oil prices are relatively consistent with current levels); and (iv) we can significantly reduce our capital expenditures for extended periods of time if necessary and still maintain current production levels as a result of our unique EOR operations.

We plan to fund the Pending CCA Acquisition with a portion of the cash proceeds from the Bakken Exchange Transaction, of which $1.05 billion was placed in qualifying trust accounts in order to qualify the acquisition for like-kind-exchange treatment for federal income tax purposes. This $1.05 billion cash was classified as Restricted Cash in our December 31, 2012 Balance Sheet. We expect the Pending CCA Acquisition to close near the end of the first quarter of 2013.

2013 Capital Spending. We currently estimate our 2013 capital spending will be approximately $1.0 billion, excluding acquisitions and $125 million of estimated capitalized costs including geological and geophysical, overhead, interest and pre-production start-up costs associated with new tertiary floods. Our current 2013 capital budget includes the following:

- $540 million allocated for tertiary oil field expenditures;
- $110 million for pipeline construction;
- $200 million to be spent on CO_2 sources; and
- $150 million to be spent in all other areas.

Based on oil and natural gas commodity futures prices in early February 2013 and our current production forecast (including production from the Pending CCA Acquisition), we estimate that our anticipated 2013 cash flow from operations should be adequate to cover our 2013 capital budget (including capitalized costs consisting of geological and geophysical, overhead, interest and pre-production start-up costs associated with new tertiary floods). If prices were to decrease or changes in operating results were to cause us to have a significant reduction in anticipated 2013 cash flows, we have ample availability on our bank credit facility to cover any potential shortfall, and we also have the ability to reduce our capital expenditures if desired.

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 2013 and some future years, we have contracted for certain capital expenditures; therefore, we cannot eliminate all of our capital commitments without penalties (see *Commitments and Obligations* for further information regarding these commitments).

Stock Repurchase Program. Our Board of Directors has approved a common share repurchase program for up to $771.2 million of Denbury common shares. As of February 21, 2013, we had repurchased approximately $521.0 million of our common stock under this program, with an additional $250.2 million of purchases authorized. See Note 7, *Stockholders' Equity* to the Consolidated Financial Statements for further discussion. Our share repurchases will be determined based on various parameters; therefore, our share repurchases may be less than the remaining approved balance under the program and there is no set expiration date for our program. We anticipate that repurchases during 2013 will be primarily funded with excess cash flow from operations or with borrowings under our bank credit facility.

Bank Credit Facility. Our primary sources of capital are our cash flow from operations and borrowings under our bank credit facility. As part of our semiannual bank review in November 2012, the borrowing base for our bank credit facility was reaffirmed at $1.6 billion. Our next borrowing base redetermination is scheduled on or around May 1, 2013. We currently do not anticipate any reduction in our borrowing base as part of that redetermination, and we believe, based on current commodity prices and our proved asset base, that we could obtain lender approval to significantly increase the borrowing base under our bank credit facility above the current $1.6 billion level if we desired to do so. As of February 21, 2013, we had no amounts outstanding under our $1.6 billion bank credit facility and estimated cash of approximately $90 million, leaving us significant liquidity to fund any cash shortfall for capital expenditures. On a pro forma basis as of February 21, 2013, assuming redemption of all remaining outstanding 9¾% Notes and 9½% Notes, we anticipate that our bank debt, net of cash, would be approximately $200 million, leaving significant availability on our bank credit facility.

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

In thousands	Year Ended December 31, 2012	2011	2010
Capital expenditures by project:			
Tertiary oil fields	$ 468,328	$ 522,007	$ 371,274
Bakken	428,313	435,159	108,363
CO_2 pipelines	181,873	134,377	171,511
CO_2 sources (1)	238,613	103,541	73,316
Other areas	159,606	244,055	156,076
Capital expenditures before acquisitions and capitalized interest	1,476,733	1,439,139	880,540
Less: recoveries from sale/leaseback transactions	(35,102)	(70,332)	(40,490)
Net capital expenditures excluding acquisitions and capitalized interest	1,441,631	1,368,807	840,050
Acquisitions:			
Property acquisitions (2)	942,359	250,084	157,929
Consideration for Encore Merger (3)	—	—	2,952,515
Capitalized interest	77,432	61,586	66,815
Capital expenditures, net of sale/leaseback transactions	$2,461,422	$1,680,477	$4,017,309

(1) Includes capital expenditures related to the Riley Ridge gas plant.

(2) In 2012, includes capital expenditures of $212.5 million related to Thompson Field that are not reflected as an Investing Activity on our Consolidated Statement of Cash Flows due to the movement of proceeds through a qualified intermediary in a like-kind exchange transaction, and $571.6 million representing the aggregate fair value of net assets acquired, excluding cash, in the Bakken Exchange Transaction. See Note 2, *Acquisitions and Divestitures* to the Consolidated Financial Statements.

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

Our 2012 capital expenditures were funded primarily with $1.4 billion of cash flow from operations, and our property acquisitions were funded with proceeds from asset sales as discussed above.

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.

Commitments Obligations

A summary of our obligations at December 31, 2012, is presented in the following table:

	Payments Due by Period				
In thousands	2013	2014 and 2015	2016 and 2017	Thereafter	Total
Contractual obligations:					
Bank Credit Agreement [1]	$ —	$ —	$ 700,000	$ —	$ 700,000
Estimated interest payments on bank credit facility and subordinated debt [1]	188,011	375,895	235,459	267,097	1,066,462
Subordinated debt [1]	—	1,557	653,520	1,396,273	2,051,350
Pipeline lease obligations [2]	30,817	64,583	61,911	296,226	453,537
Operating lease obligations	10,656	23,752	25,104	80,562	140,074
Capital lease obligations	35,429	61,768	50,090	31,806	179,093
Other obligations [3]	118,166	159,262	158,343	864,260	1,300,031
Derivative liabilities [4]	2,842	23,781	—	—	26,623
Asset retirement obligations [5]	7,042	3,745	14,285	293,798	318,870
Total contractual obligations	$392,963	$714,343	$1,898,712	$3,230,022	$6,236,040

(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. During February 2013 we issued $1.2 billion in additional senior subordinated notes and refinanced a portion of our outstanding notes and paid down borrowings under our bank credit facility, which 2013 events are not reflected above. See Note 13, *Subsequent Events,* to the Consolidated Financial Statements.

(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 CO_2 we ship through the pipeline, and the commitment amounts disclosed above for that financing lease are computed based upon our internal forecasts. Approximately $217.3 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, 2012, primarily for pipe, anthropogenic CO_2 purchase 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 2013 is currently set at $1.0 billion (see *2013 Capital Spending* above). 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 canceling 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 canceled with regard to any specific vendor, even though the expense itself may be required for our ongoing normal operations. Other obligations exclude approximately $1.3 billion of potential costs to be incurred after 2017 for anthropogenic CO_2 purchase contracts for which plant construction has not yet begun and therefore it is uncertain that we will be obligated to incur these costs.

(4) Derivative liabilities represent the fair value of our derivatives presented as liabilities in our Consolidated Balance Sheet as of December 31, 2012. 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 the estimated future asset retirement obligations on an undiscounted basis. The present value of the discounted asset retirement obligation is $106.4 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.

Off Balance-Sheet Arrangements. We have several operating leases relating to office space and other minor equipment leases. At December 31, 2012, we had a total of $16.0 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. For a further discussion of our future development costs, see Note 14, *Supplemental Oil and Natural Gas Disclosures (Unaudited),* to the Consolidated Financial Statements.

RESULTS OF OPERATIONS

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

Financial Overview of Tertiary Operations

While it is difficult to accurately forecast future production, we believe our tertiary recovery operations provide significant long-term production growth potential at reasonable rates of return, with relatively low risk. Our rate of return from our tertiary operations has generally been higher than our rate of return on traditional oil and gas operations. Generally, finding and development costs are lower and operating costs are higher than traditional oil and gas operations. We have been developing tertiary oil properties for over 13 years, and the financial impact of such operations is reflected in our historical financial statements. The summary below highlights our observations regarding how tertiary operations have impacted our financial statements.

Finding and Development Costs. We currently expect Finding and Development Costs (including future development and abandonment costs but excluding CO_2 pipeline infrastructure capital expenditures and expenditures on fields without proven reserves) over the life of each field to be lower than the industry average costs for other oil properties. See the definition of Finding and Development Costs in the *Glossary and Selected Abbreviations.*

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

Recognition of Proved Reserves. In order to recognize proved tertiary oil reserves, we must either demonstrate production resulting from the tertiary process or the field must be analogous to an existing tertiary flood. The magnitude of proven reserves that we can book in any given year will depend on our progress with new floods, the timing of the production response from new floods and the performance of our existing floods.

Production Rates. The production growth rate at a tertiary flood can vary from quarter to quarter as a tertiary field's production may increase rapidly when wells respond to the CO_2, plateau temporarily, and then resume 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 CO_2, as the CO_2 seldom travels through the rock consistently due to heterogeneity in the oil-bearing formations. We find all of these fluctuations to be normal, and generally expect oil production at a tertiary field to increase over time until the entire field is developed, albeit sometimes in inconsistent patterns.

Operating Costs. Tertiary projects may be more expensive to operate than traditional industry operations because of the cost of injecting and recycling the CO_2 (primarily due to the cost of the CO_2 and the significant energy requirements to re-compress the CO_2 back into a near-liquid state for re-injection purposes). The costs of our CO_2 and the electricity required to recycle and inject this CO_2 comprise 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. Most of our CO_2 operating costs are allocated to our tertiary oil fields and recorded as lease operating expenses (following the commencement of tertiary oil production) at the time the CO_2 is injected, 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 CO_2 (following the commencement of tertiary oil production), the operating costs per barrel will be higher at the inception of CO_2 injection projects because of minimal related oil production at that time.

Operating Results

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

In thousands, except per share and unit data	Year Ended December 31, 2012	2011	2010[1]
Operating results			
Net income attributable to Denbury stockholders	$ 525,360	$ 573,333	$ 271,723
Net income per common share – basic	1.36	1.45	0.73
Net income per common share – diluted	1.35	1.43	0.72
Net cash provided by operating activities	1,410,891	1,204,814	855,811
Average daily production volumes			
Bbls/d	66,837	60,736	59,918
Mcf/d	29,109	29,542	78,057
BOE/d	71,689	65,660	72,927
Operating revenues			
Oil sales	$2,377,337	$2,217,529	$1,661,380
Natural gas sales	32,530	51,622	131,912
Total oil and natural gas sales	$2,409,867	$2,269,151	$1,793,292
Commodity derivative contracts[2]			
Cash receipt (payment) on settlement of commodity derivative contracts	$ 17,880	$ 2,377	$ (31,612)
Non-cash fair value adjustment income (expense)	(13,046)	50,120	53,026
Total income from commodity derivative contracts	$ 4,834	$ 52,497	$ 21,414
Unit prices – excluding impact of derivative settlements			
Oil price per Bbl	$ 97.18	$ 100.03	$ 75.97
Natural gas price per Mcf	3.05	4.79	4.63
Unit prices – including impact of derivative settlements[2]			
Oil price per Bbl	$ 96.77	$ 98.90	$ 71.69
Natural gas price per Mcf	5.67	7.34	6.45
Oil and natural gas operating expenses			
Lease operating expenses	$ 532,359	$ 507,397	$ 470,364
Marketing expenses	52,836	26,047	31,036
Production and ad valorem taxes	149,919	139,170	114,980
Oil and natural gas operating revenues and expenses per BOE			
Oil and natural gas revenues	$ 91.85	$ 94.68	$ 67.37
Lease operating expenses	20.29	21.17	17.67
Marketing expenses, net of third-party purchases	1.60	1.09	1.17
Production and ad valorem taxes	5.71	5.81	4.32
CO_2 sources – revenues and expenses			
CO_2 sales and transportation fees	$ 26,453	$ 22,711	$ 19,204
CO_2 discovery and operating expenses[3]	(14,694)	(14,258)	(7,801)
CO_2 revenue and expenses, net	$ 11,759	$ 8,453	$ 11,403

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

(2) See also *Market Risk Management* below for information concerning our derivative transactions.

(3) Includes $9.5 million and $7.5 million of exploratory costs in 2012 and 2011, respectively. We incurred no exploratory costs during 2010.

Production

Average daily production by area for 2012, 2011 and 2010, and for each of the quarters of 2012, is shown below:

	Average Daily Production (BOE/d)						
	2012 Quarters				Year Ended December 31,		
Tertiary oil field	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	2012	2011	2010 (1)
Tertiary oil production							
Gulf Coast region							
Mature properties:							
Brookhaven	3,014	2,779	2,460	2,520	2,692	3,255	3,429
Eucutta	3,090	2,870	2,782	2,730	2,868	3,121	3,495
Mallalieu	2,585	2,461	2,181	2,127	2,338	2,693	3,377
Other mature properties (2)	8,012	7,867	7,347	7,605	7,707	8,955	10,240
Delhi	4,181	4,023	3,813	5,237	4,315	2,739	483
Hastings	618	1,913	2,794	3,409	2,188	—	—
Heidelberg	3,583	3,823	3,716	3,930	3,763	3,448	2,454
Oyster Bayou	877	1,304	1,540	1,826	1,388	5	—
Tinsley	7,297	8,168	8,153	8,166	7,947	6,743	5,584
Total tertiary oil production	33,257	35,208	34,786	37,550	35,206	30,959	29,062
Non-tertiary oil and gas production							
Gulf Coast region							
Mississippi	4,573	4,095	3,401	3,663	3,930	5,486	6,505
Texas	3,674	4,573	5,173	5,513	4,737	4,133	4,941
Other	1,281	1,306	1,137	1,217	1,235	1,336	1,559
Total Gulf Coast region	9,528	9,974	9,711	10,393	9,902	10,955	13,005
Rocky Mountain region							
Cedar Creek Anticline	8,496	8,535	8,490	8,493	8,503	8,968	7,930
Other	3,204	3,060	3,037	3,616	3,231	2,968	2,673
Total Rocky Mountain region	11,700	11,595	11,527	12,109	11,734	11,936	10,603
Total continuing production	54,485	56,777	56,024	60,052	56,842	53,850	52,670
Properties disposed:							
Bakken area assets (3)	15,285	15,503	16,752	10,064	14,395	9,340	4,315
Non-core asset divestitures (4)	1,762	57	—	—	452	2,470	2,288
Legacy Encore properties	—	—	—	—	—	—	6,556
ENP	—	—	—	—	—	—	7,098
Total production	71,532	72,337	72,776	70,116	71,689	65,660	72,927

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

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

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

Total Production

As outlined in the above table, continuing production increased 2,992 BOE/d (6%) between 2011 and 2012. The increases were primarily due to production increases from our tertiary oil fields, which reached record aggregate production levels in 2012, offset by normal declines in most of our other non-tertiary properties. The year-over-year 9% increase in total production was further impacted by increases in production from our Bakken area assets, which were sold late in the fourth quarter of 2012.

Continuing production increased 1,180 BOE/d (2%) between 2010 and 2011. Increases in tertiary production and Cedar Creek Anticline production due to a full year of operations were offset by normal declines at our non-tertiary fields. Total production decreased 10% due to the sale of non-strategic legacy Encore and ENP properties during 2010, offset by a 116% increase in Bakken area production.

Our production during 2012 and 2011 was 93% oil compared to 82% during 2010. 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.

Tertiary Production

Oil production from our tertiary operations increased to record levels during 2012 averaging 35,206 Bbls/d, a 14% increase over our 2011 tertiary production level of 30,959 Bbls/d, primarily due to production growth in response to continued expansion of the tertiary floods at Tinsley and Delhi fields and production at our Oyster Bayou and Hastings fields, which experienced their initial tertiary production response in late December 2011 and early January 2012, respectively. Offsetting 2012 production gains were production declines in our more mature tertiary fields. Tertiary production during the fourth quarter of 2012 increased 8% over third quarter of 2012 levels, largely due to production increases at Delhi and Hastings fields resulting from the expansion of the tertiary floods at these fields. Although all of our tertiary production is currently in the Gulf Coast region, during 2013 we plan to initiate our first tertiary operations in the Rocky Mountain region at Bell Creek Field and estimate initial production from this field to begin in the second half of 2013.

Oil production from our tertiary operations averaged 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 tertiary production gains were declines in our more mature fields.

Non-Tertiary Production

With the exception of production from our recently sold Bakken area assets and acquisitions during 2012, which have increased our production in Texas, production from our other non-tertiary properties generally declined during 2012 and 2011. Most of these conventional oil production declines are impacted by the expansion of our tertiary floods in those areas.

Our production from CCA has generally declined pending further development. During 2013, we plan to improve our waterflood at CCA through well and facility work and recompletion of existing wells, as a result of which we expect a slight increase in production. Additionally, we expect CCA volumes to increase upon the close of our Pending CCA Acquisition (see *Overview – Strategic and Value-Driven Transactions*), which to-be-acquired properties we estimate will add approximately 7,700 BOE/d to our 2013 annual production.

Production from our Bakken area assets averaged 14,395 BOE/d during 2012, compared to 9,340 BOE/d during 2011 and 4,315 BOE/d during 2010. Since we acquired the Bakken area properties in the Encore Merger, we have grown Bakken area production through an acceleration of drilling activities in that area, as we increased our operated drilling rigs from two at the time of the acquisition in March 2010, to five at the beginning of 2011 and as many as seven during the latter half of 2011. During 2012, we reduced the rig count to four, and late in the fourth quarter of 2012, we sold our Bakken area assets in the Bakken Exchange Transaction.

Oil and Natural Gas Revenues

Oil and natural gas revenues increased between 2010 and 2011 and again between 2011 and 2012. The increase in oil and natural gas revenues in 2011 was attributable to higher realized oil prices, whereas the increase in oil and natural gas revenues in 2012 was the result of increases in production volumes. 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, 2012 vs. 2011		Year Ended December 31, 2011 vs. 2010	
In thousands	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues
Change in revenues due to:				
Increase (decrease) in production	$215,150	9%	$(178,709)	(10)%
Increase (decrease) in commodity prices	(74,434)	(3)%	654,568	37%
Total increase in oil and natural gas revenues	$140,716	6%	$ 475,859	27%

Excluding any impact of our derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during 2012, 2011 and 2010:

	Year Ended December 31,		
	2012	2011	2010
Net realized prices:			
Oil price per Bbl	$ 97.18	$ 100.03	$ 75.97
Natural gas price per Mcf	3.05	4.79	4.63
Price per BOE	91.85	94.68	67.37
NYMEX differentials:			
Oil per Bbl	$ 2.99	$ 4.95	$ (3.54)
Natural gas per Mcf	0.23	0.76	0.23

As reflected in the table above, our net realized oil price declined 3% during 2012, compared to prices received during 2011, largely due to a decline in our oil price differentials between the two periods, from $4.95 per Bbl above NYMEX in 2011 to $2.99 above NYMEX in 2012. The net differential we received was primarily impacted by positive differentials in the Gulf Coast region, offset by unfavorable differentials in the Rocky Mountain region, each of which is discussed in further detail below.

We received favorable NYMEX differentials in the Gulf Coast region during 2012 and 2011, primarily due to the favorable differential for crude oil sold under LLS index prices. The quarterly average LLS-to-NYMEX differential (on a trade-month basis) ranged from a positive $12.55 per Bbl to $20.08 per Bbl for 2012, compared to a positive $9.28 per Bbl to $23.36 per Bbl during 2011. During 2012, we sold approximately 40% of our crude oil at prices based on the LLS index price and approximately 22% at prices partially tied to the LLS index price. On a pro forma basis excluding Bakken area assets sold in 2012, we sold approximately 49% of our crude oil at prices based on the LLS index price and approximately 27% at prices partially tied to the LLS index price. 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. While this differential is significant in the pricing for our oil production, other market and contractual factors may prevent us from realizing the full differential. As indicated by the above variations, the LLS-to-NYMEX differential is volatile and has been at historically high levels in recent periods, which may not continue as infrastructure is added to move barrels of oil from the U.S. Mid-continent market to the Gulf Coast.

Our production in the Rocky Mountain region has generally sold at a discount to NYMEX oil prices. Unfavorable NYMEX differentials in the Rocky Mountain region are largely impacted by oil production from our Bakken area assets, which were sold late in the fourth quarter of 2012. The realized oil prices for these sold properties averaged $15.05 per Bbl below NYMEX during 2012, compared to an average differential of $8.86 per Bbl below NYMEX during 2011. Our oil production in the Rocky Mountain region, excluding the Bakken area assets we sold in the fourth quarter of 2012, also sells at a discount to NYMEX oil prices.

Excluding oil prices received on the Bakken area assets that were sold late in the fourth quarter of 2012, our Company-wide fourth quarter average differential was $11.65 above NYMEX. Our Company-wide oil NYMEX differential improved during 2011 over our differential in 2010 primarily due to the favorable price differential for crude oil sold under LLS index pricing.

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.

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 2012, 2011 and 2010:

	Non-Cash Fair Value Gain/(Loss)			Cash Settlements Receipt/(Payment)		
In thousands	2012	2011	2010	2012	2011	2010
Crude oil derivative contracts:						
First quarter	$ (42,445)	$ (167,064)	$ 61,821	$ (8,230)	$ (5,028)	$ (63,550)
Second quarter	140,923	187,194	145,099	(709)	(16,972)	(13,829)
Third quarter	(60,726)	205,355	(62,450)	(641)	(1,857)	(3,590)
Fourth quarter	(26,848)	(166,505)	(100,029)	(411)	(1,271)	(12,448)
Full Year	$ 10,904	$ 58,980	$ 44,441	$ (9,991)	$ (25,128)	$ (93,417)
Natural gas derivative contracts:						
First quarter	$ (1,640)	$ (5,274)	$ 39,018	$ 7,040	$ 6,616	$ 3,749
Second quarter	(9,096)	(3,348)	(19,909)	7,991	6,030	16,630
Third quarter	(7,174)	229	19,933	6,910	6,427	13,626
Fourth quarter (1)	(6,040)	(467)	(30,457)	5,930	8,432	27,800
Full Year	$ (23,950)	$ (8,860)	$ 8,585	$27,871	$ 27,505	$ 61,805
Total commodity derivative contracts:						
First quarter	$ (44,085)	$ (172,338)	$ 100,839	$ (1,190)	$ 1,588	$ (59,801)
Second quarter	131,827	183,846	125,190	7,282	(10,942)	2,801
Third quarter	(67,900)	205,584	(42,517)	6,269	4,570	10,036
Fourth quarter	(32,888)	(166,972)	(130,486)	5,519	7,161	15,352
Full Year	$ (13,046)	$ 50,120	$ 53,026	$17,880	$ 2,377	$ (31,612)

(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.

Our current derivative contracts for 2013 or beyond are all NYMEX oil contracts given that our current and forecasted production is primarily oil (93% of BOE volumes in 2012), leading us to use oil derivative contracts in our commodity market risk management program. The detail of our outstanding commodity derivative contracts at December 31, 2012 is included in Note 9, *Derivative Instruments and Hedging Activities,* to the Consolidated Financial Statements.

Production Expenses

Lease operating expense

	Year Ended December 31,		
In thousands, except per BOE data	2012	2011	2010
Lease operating expense			
Tertiary	$307,686	$272,066	$229,940
Non-tertiary	224,673	235,331	240,424
Total lease operating expense	$532,359	$507,397	$470,364
Lease operating expense per BOE			
Tertiary	$ 23.88	$ 24.08	$ 21.68
Non-tertiary	16.83	18.58	15.02
Total lease operating expense per BOE	$ 20.29	$ 21.17	$ 17.67

The 5% increase in lease operating expense during 2012, compared to 2011, is due to the expansion of our tertiary operations and the resultant higher production volumes. On a per-BOE basis, lease operating expense declined 4% between the two periods due primarily to lower non-tertiary operating cost per barrel. Lease operating expense increased 8% between 2010 and 2011 on an absolute-dollar basis and 20% on a per-BOE basis.

During 2012, tertiary lease operating expense increased 13% on an absolute-dollar basis compared to 2011 levels, but decreased slightly on a per-BOE basis, from an average of $24.08 per Bbl during 2011 to an average of $23.88 per Bbl during 2012. The decrease in tertiary operating costs per barrel is due to the 14% increase in tertiary production, which more than offset the higher total tertiary operating expenses resulting from the increase in the number of our active tertiary floods due to our new tertiary floods at Hastings and Oyster Bayou fields. For any specific field, we expect our tertiary lease operating expense per barrel to be high initially, as we experienced early in 2012 with our Oyster Bayou and Hastings floods, 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 barrel will again increase.

Our higher per-barrel tertiary lease operating expense in 2011, compared to 2010, was due primarily to higher workover, power, and facility and compressor repair expenses, plus higher CO_2 expense, which is primarily due to higher oil prices. Our single highest cost for our tertiary operations is our cost for fuel and utilities, averaging $6.51 per Bbl in 2012, $6.31 per Bbl in 2011 and $5.93 per Bbl in 2010, which has increased on a per-barrel basis due to the higher cost of these items, and the continued expansion of our tertiary floods.

Currently, our CO_2 expense comprises approximately one-fourth of our typical Gulf Coast tertiary operating expenses and consists of our CO_2 production expenses, payment to CO_2 royalty owners and taxes for the CO_2 we utilize in our tertiary floods. This cost for produced CO_2, which excludes depreciation and amortization of capital expended at our Jackson Dome source and CO_2 pipelines, was approximately $0.26 per Mcf in 2012 and 2011, compared to an average cost of $0.22 per Mcf in 2010. The change in our cost of CO_2 is primarily directly attributable to changes in oil prices, as the royalty we pay to CO_2 royalty owners is directly tied to oil prices. Including the cost of depreciation and amortization expense related to the Jackson Dome CO_2 production but excluding depreciation of our CO_2 pipelines, our cost of CO_2 was $0.33 per Mcf in 2012, $0.31 per Mcf in 2011 and $0.30 per Mcf in 2010.

Non-tertiary lease operating expense decreased 5% on an absolute-dollar basis and decreased 9% on a per-BOE basis during 2012 compared to 2011. The lower operating expense per BOE was largely driven by increased production related to our Bakken area assets which had lower operating costs than our other properties, and the sale of certain non-core assets during the first half of 2012, which had a higher operating cost per BOE compared to the average of our other properties. We sold our Bakken area assets late in the fourth quarter of 2012, and thus expect our non-tertiary operating expense per BOE to increase during 2013. Excluding the Bakken area assets, our pro forma lease operating expense would have been $24.11 per BOE in 2012.

Non-tertiary lease operating costs declined between 2010 and 2011 on an absolute-dollar basis 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 increased significantly since 2010 due to new wells. Non-tertiary lease operating expense per BOE increased $3.56 (20%) between 2010 and 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.

Taxes other than income

Taxes other than income includes ad valorem, production and franchise taxes. On a per-BOE basis, taxes remained relatively steady between 2012 and 2011 and increased by 36% between 2010 and 2011. The change in each period is generally aligned with fluctuations in oil and natural gas revenues.

General and Administrative Expenses ("G&A")

In thousands, except per BOE data and employees	Year Ended December 31, 2012	2011	2010
Gross administrative costs	$ 296,696	$ 246,112	$ 231,280
Gross stock-based compensation	37,897	39,875	35,075
Operator labor and overhead recovery charges	(141,358)	(125,466)	(112,160)
Capitalized exploration and development costs	(49,216)	(34,996)	(20,074)
Net G&A expense	$ 144,019	$ 125,525	$ 134,121
G&A per BOE:			
Net administrative costs	$ 4.48	$ 3.98	$ 3.95
Net stock-based compensation	1.01	1.26	1.09
Net G&A expense	$ 5.49	$ 5.24	$ 5.04
Employees as of December 31	1,432	1,308	1,195

Net G&A expense increased 15% between 2011 and 2012 and decreased 6% between 2010 and 2011 on an absolute-dollar basis and increased 5% between 2011 and 2012 and 4% between 2010 and 2011 on a per-BOE basis.

Gross administrative costs increased $50.6 million, or 21%, between 2011 and 2012, and increased $14.8 million, or 6%, between 2010 and 2011. The increase in 2012 compared to 2011 is due to higher compensation-related costs both from an increase in headcount from year-end 2011 levels (9%), as well as higher salaries and employee bonus expense in 2012, plus an increase in other employee-related costs such as health insurance. The annual employee bonus was paid at 105% of target in 2012 as compared to 67% of target in 2011. The increased gross administrative cost in 2011 compared to 2010 is primarily due to increased expense resulting from the Encore Merger, as the 2010 period included the effect of the Encore Merger beginning on the acquisition date, March 9, 2010.

Stock-based compensation costs decreased in 2012 as compared to 2011 due to a shift in the mix of compensation awarded to employees during 2012 to include more cash-based compensation. Stock-based compensation costs increased during 2011 over 2010 levels primarily due to the increased number of employees during 2011 compared to 2010. Stock-based compensation, net of amounts reclassified to field operations or capitalized, were approximately $26.5 million in 2012, $30.3 million in 2011 and $27.9 million in 2010.

Our well operating agreements allow us, when we are the operator, to charge a well with a specified overhead rate during the drilling phase and also to charge a monthly fixed overhead rate for each producing well. In addition, salaries associated with field personnel are initially recorded as gross 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 13% between 2011 and 2012 and 12% between 2010 and 2011. Capitalized exploration and development costs also increased between the periods, primarily due to increased compensation costs subject to capitalization.

Interest and Financing Expenses

In thousands, except per BOE data and interest rates	Year Ended December 31, 2012	2011	2010
Cash interest expense	$ 216,205	$ 207,727	$ 221,759
Noncash interest expense	14,808	18,219	21,169
Less: Capitalized interest	(77,432)	(61,586)	(66,815)
Interest expense, net	$ 153,581	$ 164,360	$ 176,113
Interest expense, net per BOE	$ 5.85	$ 6.86	$ 6.62
Average debt outstanding	$2,935,485	$2,470,682	$2,736,634
Average interest rate (1)	7.4%	8.4%	8.1%

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

Interest expense, net decreased $10.8 million, or 7%, between 2012 and 2011, and decreased $11.8 million, or 7%, between 2010 and 2011. The decline in interest expense between 2011 and 2012 is largely due to higher capitalized interest, offset in part by higher cash interest expense resulting from an increase in average debt outstanding during the period. Capitalized interest increased 26% during 2012 primarily due to incremental capitalized interest on the Riley Ridge plant and Greencore Pipeline construction projects. We expect capitalized interest to decline in 2013 primarily due to (1) a lower capitalization rate resulting from the issuance of our 2023 Notes and (2) the anticipated completion of a number of projects during 2013, including the Riley Ridge gas plant and Bell Creek Field, both of which are expected to be placed into service during the first half or mid-2013.

Interest expense, net 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 6⅜% 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 CO_2 floods, Riley Ridge and the Greencore Pipeline.

See Note 5, *Long-Term Debt,* to the Consolidated Financial Statements for information regarding our February 2013 debt issuance and tender offer to refinance certain of our outstanding debt at a lower interest rate and for a longer term.

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

	Year Ended December 31,		
In thousands, except per BOE data	2012	2011	2010
Depletion and depreciation of oil and natural gas properties	$420,094	$362,788	$394,957
Depletion and depreciation of CO_2 properties	23,843	18,220	20,665
Asset retirement obligations	7,228	6,287	6,443
Depreciation of other fixed assets	56,373	21,901	21,860
Cumulative change due to revision in policy for CO_2 properties	—	—	(9,618)
Total DD&A	$507,538	$409,196	$434,307
DD&A per BOE:			
Oil and natural gas properties	$ 16.28	$ 15.40	$ 15.08
CO_2 and other fixed assets	3.06	1.67	1.60
Cumulative change due to revision in policy for CO_2 properties	—	—	(0.36)
Total DD&A cost per BOE	$ 19.34	$ 17.07	$ 16.32

We adjust our DD&A rate each quarter for significant changes in our estimates of oil and natural gas reserves and costs. In addition, under full cost accounting rules, the divestiture of oil and gas properties generally does not result in gain or loss recognition; instead, the proceeds of the disposition reduce the full cost pool. As such, our DD&A rate has changed significantly over time, and it may continue to change in the future. Depletion and depreciation of oil and natural gas properties increased between 2011 and 2012 on both an absolute-dollar basis and a per-BOE basis. During the first nine months of 2012, our DD&A rate for our oil and natural gas properties was $16.90 per BOE, which was higher than 2011 levels due to higher finding and development costs related to our Bakken capital program. However, in the fourth quarter of 2012, our DD&A rate for our oil and natural gas properties decreased to $14.39 per BOE due to the Bakken Exchange Transaction. As a result of this transaction, there was a decrease in capitalized costs relating to the sales proceeds credited to the full cost pool and a significant reduction in future development costs relating to the sold proved reserves, partially offset by the reduction in total proved reserves. Upon the completion of the Pending CCA Acquisition late in the first quarter of 2013, we expect our DD&A rate to increase from the fourth quarter of 2012 rate due to our expectation that the CCA acquisition will be recorded at a rate higher than our current DD&A rate. However, since the value at which CCA is recorded is partially dependent upon the value of the to-be-acquired assets as of the closing date of the transaction in accordance with generally accepted accounting principles, we are not able to precisely predict the DD&A impact.

Depletion and depreciation of oil and natural gas properties decreased on an absolute-dollar basis during 2011 compared to 2010, primarily due to the sale of non-strategic legacy Encore assets and our ownership interests in ENP during 2010. Depletion and depreciation 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.

During 2012, we added 114.2 MMBOE of estimated proved reserves, including tertiary reserves of 69.5 MMBbls, primarily at Hastings and Oyster Bayou fields based on these fields' responses to CO_2 injections, 25.9 MMBOE from the acquisition of interests in the Thompson, Webster and Hartzog Draw fields, and 11.5 MMBOE from our Bakken area assets prior to their sale in the fourth quarter of 2012. These increases were offset by the disposition of 123.9 MMBOE of reserves associated with the disposed properties including our Bakken area assets, non-core assets in the Gulf Coast region and the Paradox Basin of Utah. We reclassified approximately $430 million from unevaluated properties to the full cost pool relating to Hastings and Oyster Bayou fields, representing the acquisition costs and development expenditures incurred on these fields prior to recognizing proved reserves.

Depletion and depreciation of our CO_2 properties increased on an absolute-dollar and BOE basis during 2012 from 2011 levels primarily due to increased drilling activity at Jackson Dome, and depreciation of other fixed assets increased during the same period due to incremental pipeline depreciation and the change in classification of our equipment leases from operating to capital during the second quarter of 2012. See Note 5, *Long-Term Debt,* to the Consolidated Financial Statements for further discussion. Our DD&A expense for our CO_2 assets decreased in 2011 compared to 2010 due to CO_2 reserve increases at Jackson Dome at the end of 2010. On a per BOE basis, DD&A expense for our CO_2 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.

During the third quarter of 2010, we changed our method of accounting for CO_2 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 2012, 2011 or 2010. 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 and $92.3 million of transaction and other costs during 2011 and 2010, respectively, associated with the Encore Merger, including $3.6 million and $43.8 million during 2011 and 2010, respectively, related to severance costs.

During 2012, we recognized $17.5 million of impairment charges primarily related to our investment in Faustina Hydrogen Products LLC, an entity created to develop a proposed plant from which we could offtake CO_2, as a result of the project not moving forward.

Income Taxes

	Year Ended December 31,		
Amounts in thousands, except per BOE amounts and tax rates	2012	2011	2010
Current income tax expense	$ 75,754	$ 8,249	$ 33,194
Deferred income tax expense	255,743	342,463	160,349
Total income tax expense	$ 331,497	$ 350,712	$ 193,543
Average income tax expense per BOE	$ 12.63	$ 14.63	$ 7.27
Effective tax rate	38.7%	38.0%	40.4%
Total net deferred tax liability	$2,124,296	$1,868,420	$1,520,538

Our income tax provision for 2012 was based on an estimated statutory rate of approximately 38.5%, while 2011 and 2010 tax provisions were based on an estimated statutory rate of approximately 38%. The increase in our statutory rate is partly driven by a shift in the amount of revenues we earn in each state due to recent acquisitions and divestitures. Our effective tax rate was consistent with our estimated statutory rates in 2012 and 2011; however, our 2010 effective tax rate was higher than the estimated statutory rate in that year primarily due to the recognition of additional net tax expense on the revaluation of our deferred taxes at the date of the Encore Merger.

During 2012, for federal income tax purposes, we structured the divestitures of our Bakken area assets and certain non-core assets as like-kind-exchange transactions for interests acquired in Thompson, Webster, Hartzog Draw and LaBarge fields and assets to be acquired in the Pending CCA Acquisition, thereby deferring the majority of the taxable gain on those divestitures. The increase in current income tax expense during 2012 includes $42 million of current taxes resulting from the taxable gain recognized in the Bakken Exchange Transaction that we were unable to defer through a like-kind-exchange transaction. Current income tax expense during 2012, 2011 and 2010 also includes our anticipated alternative minimum cash taxes that we cannot offset with enhanced oil recovery credits, as well as state income taxes. Our current income tax expense during 2011 was offset by 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.

As of December 31, 2012, we had an estimated $17.3 million of enhanced oil recovery credits to carry forward that can be utilized to reduce our current income taxes during 2013 or future years, down from $53.4 million in 2011 due to current year utilization. These enhanced oil recovery credits do not begin to expire until 2025. 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.

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	2012	2011	2010
Oil and natural gas revenues	$ 91.85	$ 94.68	$ 67.37
Gain (loss) on settlements of derivative contracts	0.68	0.10	(1.19)
Lease operating expenses	(20.29)	(21.17)	(17.67)
Production and ad valorem taxes	(5.71)	(5.81)	(4.32)
Marketing expenses, net of third party purchases	(1.60)	(1.09)	(1.17)
Production netback	64.93	66.71	43.02
CO_2 sales, net of operating expenses	0.45	0.36	0.43
General and administrative expenses	(5.49)	(5.24)	(5.04)
Transaction costs and other costs related to the Encore Merger	—	(0.18)	(3.47)
Interest expense, net	(5.85)	(6.86)	(6.62)
Other	(1.44)	1.95	0.77
Changes in assets and liabilities relating to operations	1.17	(6.47)	3.06
Cash flow from operations	53.77	50.27	32.15
DD&A	(19.34)	(17.07)	(16.32)
Deferred income taxes	(9.75)	(14.29)	(6.02)
Gain on sale of interests in Genesis	—	—	3.81
Loss on early extinguishment of debt	—	(0.67)	—
Non-cash commodity derivative adjustments	(0.50)	2.09	1.99
Net income attributable to noncontrolling interest	—	—	(0.52)
Impairment of assets	(0.67)	(0.96)	—
Other non-cash items	(3.49)	4.55	(4.88)
Net income	$ 20.02	$ 23.92	$ 10.21

Market Risk Management

Restricted Cash

Restricted cash on our Consolidated Balance Sheet as of December 31, 2012 consists of proceeds from the Bakken Exchange Transaction (see Note 2, *Acquisitions and Divestitures,* to the Consolidated Financial Statements) being held by a qualified intermediary through three separate financial institutions and which are restricted for application towards future acquisitions to facilitate an anticipated like-kind-exchange transaction for federal income tax purposes. We manage and control counterparty credit risk related to this restricted cash using a trust agreement, whereby the assets held in trust must be segregated from the financial institution's assets, and in the event of its bankruptcy, the funds would not be subject to payments to the creditors of the financial institution.

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, 2012, we had $700 million in outstanding borrowings on our bank credit facility. None of our existing debt has any triggers or covenants regarding our debt ratings with rating agencies, although under the NEJD financing lease, in the event of significant downgrades of our corporate credit rating by the rating agencies, certain credit enhancements can be required from us, and possibly other remedies made available under the lease. 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, 2012.

In thousands	2014	2015	2016	2017	2020	2021	Total	Fair Value
Variable rate debt:								
Bank credit facility (weighted average interest rate of 1.96% at December 31, 2012)	$ —	$ —	$700,000	$ —	$ —	$ —	$700,000	$ 700,000
Fixed rate debt:								
9½% Senior Subordinated Notes due 2016	—	—	224,920	—	—	—	224,920	240,372
9¾% Senior Subordinated Notes due 2016	—	—	426,350	—	—	—	426,350	451,931
8¼% Senior Subordinated Notes due 2020	—	—	—	—	996,273	—	996,273	1,120,807
6⅜% Senior Subordinated Notes due 2021	—	—	—	—	—	400,000	400,000	440,000
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, including information regarding our February 2013 debt issuance and tender offers to refinance certain of our outstanding debt at a lower interest rate and for a longer term.

Oil and Natural Gas Derivative Contracts

From time to time, we enter into oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production. These contracts have consisted of price floors, collars and fixed price swaps. We do not hold or issue derivative financial instruments for trading purposes. The production that we hedge has varied from year to year, depending on our levels of debt and financial strength and expectation of future commodity prices. We currently employ a strategy to hedge a portion of our forecasted production for approximately two years 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 *Capital Resources and Liquidity* above). We recently extended this from a period closer to a year and a half into the future, due in part to slightly higher leverage. We do not have any natural gas derivative contracts for 2013 or beyond. Because our current and forecasted production is primarily oil (93% of BOE volumes in 2012), we use oil derivative contracts in our commodity market risk management program. 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, 2012, our derivative contracts were recorded at their fair value, which was a net liability of approximately $6.9 million, a $13.0 million decrease from the $6.1 million net asset recorded at December 31, 2011. This change is primarily related to the expiration of oil and natural gas derivative contracts during 2012 and to the oil futures prices as of December 31, 2012, in relation to the new commodity derivative contracts we entered into during 2012 for future periods.

Commodity Derivative Sensitivity Analysis

Based on NYMEX crude oil and natural gas futures prices as of December 31, 2012, and assuming both a 10% increase and decrease thereon, we would expect to make or receive payments on our crude oil derivative contracts as shown in the following table:

In thousands	Crude Oil Derivative Contracts Receipt/ (Payment)
Based on:	
NYMEX futures prices as of December 31, 2012	$ —
10% increase in prices	(35,849)
10% decrease in prices	—

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, annual revisions to our reserve estimates have averaged approximately 1.7% of the previous year's estimates and have been both positive and negative.

Changes in commodity prices also affect our reserve quantities. Between 2010 and 2011, oil prices used to calculate reserve quantities in our year-end proved reserve report increased, resulting in an additional increase in our proved reserves of 2.6 MMBOE. Between 2011 and 2012, oil and natural gas prices used to calculate year-end proved reserves decreased, resulting in a decrease in our proved reserves of 6.7 MMBOE. These changes in quantities affect our DD&A rate, and the combined effect of changes in quantities and commodity prices impacts our full cost ceiling test calculation. For example, we estimate that a 5% increase in our estimate of proved reserves quantities would have lowered our fourth quarter 2012 DD&A rate from $18.20 per BOE to approximately $17.54 per BOE, and a 5% decrease in our proved reserve quantities would have increased our DD&A rate to approximately $18.93 per BOE. Also, reserve quantities and their ultimate values, determined solely by our lenders, are the primary factors in determining the maximum borrowing base under our bank credit facility.

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

We did not have a full cost pool ceiling test write-down in 2012, 2011 or 2010. Crude oil prices increased between 2010 and 2011, but decreased slightly during 2012, with first-day-of-the-month NYMEX oil prices during 2012 averaging $94.71 per Bbl during the year. First-day-of-the-month unweighted average NYMEX natural gas prices during 2012 of $2.85 per Mcf were lower than 2011 levels due to declining prices early in 2012. Natural gas prices began to rise later in 2012, ending the year at $3.35 per Mcf at December 31, 2012. 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 CO_2 injection until we can demonstrate production resulting from the tertiary process or unless the field is analogous to an existing flood. Our costs associated with the CO_2 we produce (or acquire) and inject are principally our cash out-of-pocket costs of production, transportation and acquisition, and to pay royalties.

We capitalize, as a development cost, injection costs in fields that are in their development stage, which means we have not yet seen incremental oil production due to the CO_2 injections (i.e., a production response). These capitalized development costs will be included in our unevaluated property costs if there are not already proved tertiary reserves in that field. After we see a production response to the CO_2 injections (i.e., the production stage), injection costs will be expensed as incurred, and any previously deferred unevaluated development costs will become subject to depletion upon recognition of proved tertiary reserves. During 2012, 2011 and 2010, we capitalized $36.8 million, $65.3 million and $20.5 million, respectively, of tertiary injection costs associated with our tertiary projects.

Income Taxes

We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Our federal and state income tax returns are generally not prepared or filed before the consolidated financial statements are prepared; therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and net operating loss carryforwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we finalize our income tax returns. Further, we must assess the likelihood that we will be able to recover or utilize our deferred tax assets (primarily our enhanced oil recovery credits and state loss carryforwards). If recovery is not likely, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover, which would result in an increase to our income tax expense. As of December 31, 2012, 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 by approximately $8.6 million, $9.2 million and $4.8 million for the years ended December 31, 2012, 2011 and 2010, 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. We use all available information to estimate the fair values of assets acquired and liabilities assumed in an acquisition and engage a third-party consultant to review certain assumptions utilized in our valuations.

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

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

Impairment Assessment of Goodwill

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

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

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

- Macroeconomic conditions, such as deterioration in general economic conditions, limitations on accessing capital, or other developments in equity and credit markets;
- Industry and market conditions, such as deterioration in the environment in which we operate, including significant declines in oil prices, inability to access oil field equipment and/or qualified personnel and regulations impacting the oil and natural gas industry, among others;
- Cost factors, such as increases in power and labor costs;

- Overall financial performance, such as negative or declining cash flows or a decline in actual or forecasted revenues or earnings;
- Other relevant Company-specific events, such as material changes in management or key personnel, a change in strategy or litigation;
- Material events, such as a change in the composition or carrying amount of our reporting unit's net assets, including acquisitions and dispositions; and
- Consideration of the relationship of our market capitalization to our book value, as well as a sustained decrease in our share price.

If we determine that it is more likely than not that our reporting unit's fair value is less than its carrying amount, we will proceed to step 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 and net asset value when appropriate. The Company also takes into consideration the Company's market capitalization, including a control premium. 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 CO_2, 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.

We completed our goodwill impairment assessment during the fourth quarter of 2012 and did not record any goodwill impairment during 2012, nor have we recorded a goodwill impairment historically.

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 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 2012, 2011 and 2010, we recognized expense (income) of $13.0 million, $(50.1) million and $(53.0) 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 our 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.

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, completion of pending acquisitions and the hydrocarbon reserves and production attributable to them, timing of CO_2 injections and initial production responses in tertiary flooding projects, acquisition plans and proposals and dispositions, development activities, finding costs, cost savings, capital budgets, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO_2 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 words that convey the uncertainty of future events or outcomes. Such forward-looking information is based upon management’s current plans, expectations, estimates and assumptions and is subject to a number of risks and uncertainties that could significantly affect current plans, anticipated actions, the timing of such actions and our financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by us or on our behalf. Among the factors that could cause actual results to differ materially are fluctuations of the prices received or demand for our oil and natural gas; effects of our indebtedness; success of our risk management techniques; inaccurate cost estimates; availability of and fluctuations in the prices of goods and services; the uncertainty of drilling results and reserve estimates; operating hazards; disruption of operations and damages from hurricanes or tropical storms; acquisition risks; requirements for capital or its availability; conditions in the financial and credit markets; general economic conditions; competition and government regulations; and unexpected delays, as well as the risks and uncertainties inherent in oil and gas drilling and production activities or that are otherwise discussed in this annual report, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in our other public reports, filings and public statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

Item 8. Financial Statements and Supplementary Data

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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 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, 2012, 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.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Dallas, Texas
February 28, 2013

CONSOLIDATED BALANCE SHEETS

In thousands, except par value and share data	December 31, 2012	December 31, 2011
Assets		
Current assets		
Cash and cash equivalents	$ 98,511	$ 18,693
Restricted cash	1,050,015	—
Accrued production receivable	253,131	294,689
Trade and other receivables, net	81,971	164,446
Short-term investments	—	86,682
Derivative assets	19,477	47,402
Deferred tax assets	29,156	50,156
Other current assets	10,493	22,045
Total current assets	1,542,754	684,113
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved	6,963,211	7,026,579
Unevaluated	809,154	1,157,106
CO_2 properties	1,032,653	596,003
Pipelines and plants	2,035,126	1,701,756
Other property and equipment	417,207	157,674
Less accumulated depletion, depreciation, amortization and impairment	(3,180,241)	(2,627,493)
Net property and equipment	8,077,110	8,011,625
Derivative assets	36	29
Goodwill	1,283,590	1,236,318
Other assets	235,852	252,339
Total assets	$11,139,342	$10,184,424
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 414,668	$ 429,336
Oil and gas production payable	161,945	197,092
Derivative liabilities	2,842	26,523
Current maturities of long-term debt	36,966	8,316
Total current liabilities	616,421	661,267
Long-term liabilities		
Long-term debt, net of current portion	3,104,462	2,669,729
Asset retirement obligations	102,730	88,726
Derivative liabilities	23,781	18,872
Deferred taxes	2,153,452	1,918,576
Other liabilities	23,607	20,756
Total long-term liabilities	5,408,032	4,716,659
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; 406,163,194 and 402,946,070 shares issued, respectively	406	403
Paid-in capital in excess of par	3,136,461	3,090,374
Retained earnings	2,434,835	1,909,475
Accumulated other comprehensive loss	(348)	(418)
Treasury stock, at cost, 30,601,262 and 13,965,673 shares, respectively	(456,465)	(193,336)
Total stockholders' equity	5,114,889	4,806,498
Total liabilities and stockholders' equity	$11,139,342	$10,184,424

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF OPERATIONS

In thousands, except per share data	Year Ended December 31, 2012	2011	2010
Revenues and other income			
Oil, natural gas, and related product sales	$2,409,867	$2,269,151	$1,793,292
CO_2 sales and transportation fees	26,453	22,711	19,204
Gain on sale of interests in Genesis	—	—	101,537
Interest income and other income	20,152	17,462	7,758
Total revenues and other income	2,456,472	2,309,324	1,921,791
Expenses			
Lease operating expenses	532,359	507,397	470,364
Marketing expenses	52,836	26,047	31,036
CO_2 discovery and operating expenses	14,694	14,258	7,801
Taxes other than income	160,016	147,534	120,541
General and administrative expenses	144,019	125,525	134,121
Interest, net of amounts capitalized of $77,432, $61,586 and $66,815, respectively	153,581	164,360	176,113
Depletion, depreciation and amortization	507,538	409,196	434,307
Derivatives expense (income)	(4,834)	(52,497)	(23,833)
Loss on early extinguishment of debt	—	16,131	—
Transaction and other costs related to the Encore Merger	—	4,377	92,271
Impairment of assets	17,515	22,951	—
Other expenses	21,891	—	—
Total expenses	1,599,615	1,385,279	1,442,721
Income before income taxes	856,857	924,045	479,070
Income tax provision	331,497	350,712	193,543
Consolidated net income	525,360	573,333	285,527
Less: net income attributable to noncontrolling interest	—	—	(13,804)
Net income attributable to Denbury stockholders	$ 525,360	$ 573,333	$ 271,723
Net income per common share – basic	$ 1.36	$ 1.45	$ 0.73
Net income per common share – diluted	1.35	1.43	0.72
Weighted average common shares outstanding			
Basic	385,205	396,023	370,876
Diluted	388,938	400,958	376,255

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE OPERATIONS

	Year Ended December 31,		
In thousands	2012	2011	2010
Consolidated net income	$525,360	$573,333	$285,527
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	70	69
Change in deferred hedge loss on interest rate swaps, net of tax benefit of $62	—	—	(83)
Total other comprehensive income (loss)	70	70	(14)
Comprehensive income	525,430	573,403	285,513
Less: comprehensive income attributable to noncontrolling interest	—	—	(13,727)
Comprehensive income attributable to Denbury stockholders	$525,430	$573,403	$271,786

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
In thousands	2012	2011	2010
Cash flow from operating activities:			
Consolidated net income	$ 525,360	$ 573,333	$ 285,527
Adjustments to reconcile consolidated net income to cash flow from operating activities:			
Depletion, depreciation and amortization	507,538	409,196	434,307
Deferred income taxes	255,743	342,463	160,349
Gain on sale of interests in Genesis	—	—	(101,537)
Stock-based compensation	29,310	33,190	35,366
Noncash fair value derivative adjustments	13,159	(50,008)	(55,445)
Loss on early extinguishment of debt	—	16,131	—
Amortization of debt issuance costs and discounts	14,695	16,954	17,876
Impairment of assets	17,515	22,951	—
Other, net	16,804	(4,302)	(2,144)
Changes in assets and liabilities, net of effects from acquisitions:			
Accrued production receivable	36,234	(74,781)	2,426
Trade and other receivables	45,836	(55,470)	24,977
Other current and long-term assets	7,688	(15,817)	(4,119)
Accounts payable and accrued liabilities	5,828	(35,462)	48,549
Oil and natural gas production payable	(23,460)	54,391	15,565
Other liabilities	(41,359)	(27,955)	(5,886)
Net cash provided by operating activities	1,410,891	1,204,814	855,811
Cash flow used for investing activities:			
Oil and natural gas capital expenditures	(1,122,615)	(1,082,853)	(671,574)
Acquisitions of oil and natural gas properties	(156,082)	(35,305)	(25,672)
Cash paid in Encore Merger and Riley Ridge acquisitions	—	(199,263)	(947,241)
Cash received in Bakken Exchange Transaction	281,669	—	—
CO_2 capital expenditures	(131,043)	(84,789)	(93,556)
Pipelines and plants capital expenditures	(330,417)	(236,133)	(207,536)
Purchases of other assets	(25,765)	(28,838)	(28,684)
Net proceeds from sale of interests in Genesis	—	—	162,619
Net proceeds from sales of oil and natural gas properties and equipment	34,750	69,370	1,458,029
Net proceeds from sale of short-term investments	83,545	—	—
Other	(10,883)	(8,147)	(1,165)
Net cash used for investing activities	(1,376,841)	(1,605,958)	(354,780)
Cash flow provided by (used for) financing activities:			
Bank repayments	(1,555,000)	(330,000)	(1,530,000)
Bank borrowings	1,870,000	715,000	1,114,000
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
Costs of debt financing	(34)	(13,123)	(76,251)
ENP distributions to noncontrolling interest	—	—	(36,738)
Common stock repurchase program	(251,480)	(195,227)	—
Other	(17,718)	(545)	5,873
Net cash provided by (used for) financing activities	45,768	37,968	(139,753)
Net increase (decrease) in cash and cash equivalents	79,818	(363,176)	361,278
Cash and cash equivalents at beginning of year	18,693	381,869	20,591
Cash and cash equivalents at end of year	$ 98,511	$ 18,693	$ 381,869

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	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	Total Equity
Dollar amounts in thousands	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	$ —	$ 1,972,237
Repurchase of common stock	—	—	—	—	—	413,869	(6,729)	(6,729)	—	(6,729)
Issued pursuant to employee stock purchase plan	—	—	325	—	—	(491,629)	7,872	8,197	—	8,197
Issued pursuant to employee stock option plan	999,077	1	4,867	—	—	—	—	4,868	—	4,868
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	—	2,085,681
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	—	39,791
Income tax benefit from equity awards	—	—	4,603	—	—	—	—	4,603	—	4,603
ENP revaluation at Encore Merger	—	—	—	—	—	—	—	—	515,210	515,210
ENP cash distributions to noncontrolling interest	—	—	—	—	—	—	—	—	(36,738)	(36,738)
Sale of ENP	—	—	—	—	—	—	—	—	(492,193)	(492,193)
Derivative contracts, net	—	—	—	—	69	—	—	69	(83)	(14)
Consolidated net income	—	—	—	271,723	—	—	—	271,723	13,804	285,527
Balance – December 31, 2010	400,291,033	400	3,045,937	1,336,142	(488)	78,524	(1,284)	4,380,707	—	4,380,707
Repurchase of common stock	—	—	—	—	—	441,406	(9,683)	(9,683)	—	(9,683)
Issued pursuant to employee stock purchase plan	11,330	—	(1,623)	—	—	(666,867)	12,858	11,235	—	11,235
Stock Repurchase Program	—	—	—	—	—	14,112,610	(195,227)	(195,227)	—	(195,227)
Issued pursuant to employee stock option plan	1,200,759	1	4,685	—	—	—	—	4,686	—	4,686
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	—	40,187
Income tax benefit from equity awards	—	—	879	—	—	—	—	879	—	879
Derivative contracts, net	—	—	—	—	70	—	—	70	—	70
Net income	—	—	—	573,333	—	—	—	573,333	—	573,333
Balance – December 31, 2011	402,946,070	403	3,090,374	1,909,475	(418)	13,965,673	(193,336)	4,806,498	—	4,806,498
Repurchase of common stock	—	—	—	—	—	472,966	(8,125)	(8,125)	—	(8,125)
Issued pursuant to employee stock purchase plan	—	—	1,607	—	—	(815,385)	11,653	13,260	—	13,260
Stock Repurchase Program	—	—	—	—	—	16,978,008	(266,657)	(266,657)	—	(266,657)
Issued pursuant to employee stock option plan	1,429,309	1	6,022	—	—	—	—	6,023	—	6,023
Issued pursuant to directors' compensation plan	19,648	—	321	—	—	—	—	321	—	321
Restricted stock grants	1,909,739	2	(1)	—	—	—	—	1	—	1
Restricted stock grants – forfeited	(261,762)	—	—	—	—	—	—	—	—	—
Performance-based shares issued	120,190	—	—	—	—	—	—	—	—	—
Stock-based compensation	—	—	37,897	—	—	—	—	37,897	—	37,897
Income tax benefit from equity awards	—	—	241	—	—	—	—	241	—	241
Derivative contracts, net	—	—	—	—	70	—	—	70	—	70
Net income	—	—	—	525,360	—	—	—	525,360	—	525,360
Balance – December 31, 2012	406,163,194	$406	$3,136,461	$2,434,835	$ (348)	30,601,262	$(456,465)	$5,114,889	$ —	$ 5,114,889

See accompanying 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 CO_2 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 the most significant emphasis relating to CO_2 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 other 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 the March 9, 2010 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 ("ENP GP LLC") membership interests, which was ENP's general partner. Considering the presumption of control of ENP 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 ENP GP LLC; 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.

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) the estimated quantities of proved and probable CO_2 reserves used to compute depletion of CO_2 properties; (4) accruals related to oil and natural gas sales volumes and revenues, capital expenditures and lease operating expenses; (5) the estimated costs and timing of future asset retirement obligations; (6) estimates made in the calculation of income taxes; and (7) 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.

Reclassifications

Certain prior period amounts have been reclassified to conform with the current year presentation. Such reclassifications had no impact on our reported 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.

Restricted Cash

Restricted cash at December 31, 2012 consists of proceeds from the exchange of oil and gas properties with Exxon Mobil Corporation and its wholly-owned subsidiary XTO Energy Inc. (see Note 2, *Acquisitions and Divestitures*) being held by a qualified intermediary through three separate financial institutions and which are restricted for application towards future potential acquisitions to facilitate an anticipated like-kind-exchange transaction for federal income tax purposes. We manage and control counterparty credit risk related to this restricted cash using a trust agreement, whereby the assets held in trust must be segregated from the financial institution's assets, and in the event of a bankruptcy, the funds would not be subject to payments to the creditors of the financial institution.

Short-term Investments

Short-term investments represent available-for-sale securities recorded at fair value with any unrealized gains or losses included in accumulated other comprehensive income. At December 31, 2011, 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 owned 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 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. During January 2012, we sold our investment in Vanguard for cash consideration of $83.5 million, net of related transaction fees. The Company recognized a pretax loss on the sale of $3.1 million, which is included in "Other expenses" on our Consolidated Statements of Operations for the year ended December 31, 2012.

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 nonproductive wells, capitalized interest on qualifying projects, and general and administrative expenses directly related to exploration and development activities, and do not include any costs related to production, general corporate overhead or similar activities. We assign the purchase price of oil and natural gas properties we acquire to proved and unevaluated properties based on the estimated fair values as defined in the 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. A disposal of twenty-five percent or more of our proved reserves would be considered significant.

Depletion and Depreciation. The costs capitalized, including production equipment and future development costs, are depleted or depreciated using the unit-of-production method, based on proved oil and natural gas reserves as determined by independent petroleum engineers. Oil and natural gas reserves are converted to equivalent units on a basis of 6,000 cubic feet of natural gas to one barrel of crude oil. The depletion and depreciation rate per BOE associated with our oil and gas producing activities was $18.69 in 2012, $16.42 in 2011 and $15.82 in 2010.

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

Ceiling Test. The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized cost or the cost center ceiling. The cost center ceiling is defined as: (1) the present value of estimated future net revenues from proved reserves before future abandonment costs (discounted at 10%), based on the average first-day-of-the-month oil and natural gas price for each month during the 12-month period prior to the end of a particular reporting period; plus (2) the cost of properties not being amortized; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) related income tax effects. Our future net revenues from proved reserves are not reduced for development costs related to the cost of drilling for and developing CO_2 reserves nor those related to the cost of constructing CO_2 pipelines, as those costs have previously been incurred by the Company. Therefore, we include in the ceiling test, as a reduction of future net revenues, that portion of our capitalized CO_2 costs related to CO_2 reserves and CO_2 pipelines that we estimate will be consumed in the process of producing our proved oil and natural gas reserves. The fair value of our oil and natural gas derivative contracts is not included in the ceiling test, as we do not designate these contracts as hedge instruments for accounting purposes. The cost center ceiling test is prepared quarterly. We did not have a ceiling test write-down during the years ended December 31, 2012, 2011 or 2010.

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

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

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

CO_2 Properties

We own and produce CO_2 reserves, a non-hydrocarbon resource, that are used in our tertiary oil recovery operations on our own behalf and on behalf of other interest owners in enhanced recovery fields, with a portion sold to third-party industrial users. We record revenue from our sales of CO_2 to third parties when it is produced and sold. Expenses related to the production of CO_2 are allocated between volumes sold to third parties and volumes consumed internally that are directly related to our tertiary production. The expenses related to third-party sales are recorded in "CO_2 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 CO_2 (see *Tertiary Injection Costs* above for further discussion).

During 2010 and 2011, we acquired interests in the Riley Ridge Federal Unit ("Riley Ridge"), in which helium and CO_2 (non-hydrocarbon resources) as well as natural gas (a hydrocarbon resource) are present. It is not possible to separately identify the capitalized costs related to the development of each product in the commingled gas stream; thus, these costs are allocated to each product based on the relative future revenue value of each product line and classified accordingly on the Consolidated Balance Sheets.

During 2010, we revised our capitalization policies for CO_2 properties. Previously, we accounted for our CO_2 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 CO_2 reserves are virtually identical to those used to identify, develop and produce oil and natural gas reserves. However, because CO_2 is not a hydrocarbon, it is excluded from the scope of FASC Topic 932, *Extractive Industries – Oil and Gas;* therefore, we are precluded from accounting for our CO_2 operations in accordance with FASC Topic 932. Accordingly, commencing in July 2010, costs incurred to search for CO_2 are expensed as incurred until proved or probable reserves are established. Once proved or probable reserves are established, costs incurred to obtain those reserves are capitalized and classified as "CO_2 properties" on our Consolidated Balance Sheets. Capitalized CO_2 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. We recognized the cumulative impact of the revised accounting policy as a noncash 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 "CO_2 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 our capitalized CO_2 costs related to CO_2 reserves and CO_2 pipelines that we estimate will be consumed in the process of producing our proved oil reserves is included in the ceiling test as a reduction to future net revenues. The remaining net capitalized CO_2 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 CO_2 to third-party industrial users.

Pipelines and Plants

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

Pipelines and plants include the Riley Ridge gas 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 mid-2013.

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 abandoning our oil, natural gas and CO_2 wells, removing equipment and facilities from leased acreage, and returning land to its original condition. The fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using our credit-adjusted-risk-free interest rate, and a corresponding amount capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted each period, and the capitalized cost is depreciated over the useful life of the related asset. Revisions to estimated retirement obligations will result in an adjustment to the related capitalized asset and corresponding liability. If the liability 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 our 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 it is more likely than not the fair value of a reporting unit with goodwill has been reduced below its carrying value. The impairment test requires allocating goodwill and other assets and liabilities to reporting units. However, we have only one reporting unit. To assess impairment, we have the option to qualitatively assess if it is more likely than not that the fair value of the reporting unit is less than the carrying value. Absent a qualitative assessment, or, through the qualitative assessment, if we determine it is more likely than not that the fair value of the reporting unit is less than the carrying value, a quantitative assessment is prepared to calculate the fair market value of the reporting unit. If it is determined that the fair value of the reporting unit is less than the carrying value, the recorded goodwill is impaired to its implied fair value with a charge to operating expense. We completed our annual goodwill impairment assessment during the fourth quarter of 2012 and did not record any goodwill impairment during 2012, nor have we recorded a goodwill impairment historically.

The following table summarizes the changes in goodwill for the years ended December 31, 2012 and 2011:

In thousands	Year Ended December 31, 2012	2011
Beginning of year balance	$1,236,318	$1,232,418
Goodwill related to the Riley Ridge acquisition	—	3,900
Goodwill related to the Thompson Field acquisition	47,272	—
End of year balance	$1,283,590	$1,236,318

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, 2012 and 2011, our aggregate oil and natural gas imbalances were not material to our consolidated financial statements.

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

Income Taxes

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

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

Net Income Per Common Share

Basic net income per common share is computed by dividing the net income attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income per common share is calculated in the same manner, but includes the impact of potentially dilutive securities. Potentially dilutive securities consist of stock options, stock appreciation rights (“SARs”), nonvested restricted stock and nonvested performance equity awards. For each of the three years in the period ended December 31, 2012, 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	2012	2011	2010
Basic weighted average common shares	385,205	396,023	370,876
Potentially dilutive securities:			
Stock options and SARs	2,584	3,539	3,844
Performance equity awards	86	38	319
Restricted stock	1,063	1,358	1,216
Diluted weighted average common shares	388,938	400,958	376,255

Basic weighted average common shares excludes 3.7 million, 3.4 million and 3.2 million shares of nonvested restricted stock during the year ended December 31, 2012, 2011 and 2010, 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 nonvested 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 antidilutive:

	Year Ended December 31,		
In thousands	2012	2011	2010
Stock options and SARs	4,068	5,017	3,671
Restricted stock	47	104	17

Recent Accounting Pronouncements

Presentation of Comprehensive Income. In June 2011, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“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. ASU 2011-05 was effective for Denbury beginning January 1, 2012. Since ASU 2011-05 only amended presentation requirements, it did not have a material effect on our consolidated financial statements.

Accumulated Other Comprehensive Income Reclassifications. In February 2013, the FASB issued ASU 2013-02, *Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income* ("ASU 2013-02"). ASU 2013-02 requires disclosure of amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required to be reclassified to net income in its entirety in the same reporting period. For amounts not reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures that provide additional detail about those amounts. ASU 2013-02 is effective prospectively for our fiscal year beginning January 1, 2013. The adoption of ASU 2013-02 will not 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 was effective for Denbury beginning January 1, 2012. The adoption of ASU 2011-04 did not have a material effect on our consolidated financial statements, but did require additional disclosures. See Note 10, *Fair Value Measurements*.

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. In January 2013, the FASB issued ASU 2013-01, *Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities* ("ASU 2013-01"). The update clarifies that the scope of ASU 2011-11 applies to derivatives accounted for in accordance with the *Derivatives and Hedging* topic of the FASC, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset or subject to an enforceable master netting arrangement or similar agreement. ASU 2011-11 and ASU 2013-01 are 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 and ASU 2013-01 will not have a material effect on our consolidated financial statements, but may require additional disclosures.

Note 2. Acquisitions and Divestitures

Acquisitions and Exchange Transaction

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.

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 may include: (1) NYMEX oil and natural gas futures (this input is observable); (2) dollar-per-acre values of recent sale transactions (this input is observable); (3) projections of the estimated quantities of oil and natural gas reserves, including those classified as proved, probable and possible; (4) estimated oil and natural gas pricing differentials; (5) projections of future rates of production; (6) timing and amount of future development and operating costs; (7) projected costs of CO_2 (to a market participant); (8) projected reserve recovery factors; and (9) risk-adjusted discount rates.

Bakken Exchange Transaction. In late 2012, we closed a sale and exchange transaction with Exxon Mobil Corporation and its wholly-owned subsidiary XTO Energy Inc. (collectively, "ExxonMobil") under which we sold to ExxonMobil our Bakken area assets in North Dakota and Montana in exchange for $1.3 billion in cash (after preliminary closing adjustments) and the following assets:

- operating interests in the Webster Field, a planned future tertiary field, located in southeastern Texas, made up of a nearly 100% working interest and nearly 80% revenue interest;

- operating interests in the Hartzog Draw Field, a planned future tertiary field, located in Wyoming, consisting of an 83% working interest and 71% net revenue interest in the oil-producing Shannon Sandstone zone and a 67% working interest and 53% net revenue interest in the natural gas producing Big George Coal zone; and
- approximately a one-third overriding royalty ownership interest in ExxonMobil's CO_2 reserves in LaBarge Field in Wyoming.

The exchange of properties closed in two phases on November 30, 2012 and December 21, 2012, and is collectively referred to as the "Bakken Exchange Transaction".

Our acquisition of property interests constitutes a business combination under the FASC *Business Combinations* topic. Accordingly, the purchase price of the acquisition is measured as the fair value of consideration transferred, which consists of our Bakken area assets. The fair value of Bakken area net assets transferred to ExxonMobil in the Bakken Exchange Transaction was measured using a discounted future net cash flow model for developed properties and a market dollar-per-acre value for undeveloped properties. The fair value of assets transferred in the Bakken Exchange Transaction was measured at the dates control was transferred to ExxonMobil, which were November 30, 2012 and December 21, 2012 for 82.5% and 17.5%, respectively, of our interest in our Bakken area assets. The fair value of oil and gas properties received from ExxonMobil in such transaction was measured using a discounted future net cash flow model, and the fair value of CO_2 interests received was measured using a market-based approach, at the date control was transferred to Denbury, which was November 30, 2012, for the acquisition of interests in Webster and Hartzog Draw fields and December 21, 2012, for the acquisition of interests in LaBarge Field. We did not record a gain or loss on the exchange in accordance with the full cost method of accounting.

The following table presents a summary of the preliminary fair value of assets acquired and liabilities assumed in the Bakken Exchange Transaction:

In thousands	
Consideration:	
Fair value of net assets transferred	$1,903,280
Less: Fair value of assets acquired and liabilities assumed: (1)	
Cash (2)	1,331,684
Oil and natural gas properties	
Proved	201,301
Unevaluated	98,635
CO_2 properties	314,505
Other assets	477
Other liabilities	(29,531)
Asset retirement obligations	(13,791)
Fair value of net assets acquired	$1,903,280

(1) Fair value of the assets acquired and liabilities assumed is preliminary, pending final closing adjustments and further evaluation of reserves and asset retirement obligations.

(2) Cash proceeds include preliminary closing adjustments of $41.7 million primarily representing adjustments for net revenues and capital expenditures of the transferred oil and natural gas property assets from the Bakken Exchange Transaction effective date to the closing dates. Also see Note 12, *Supplemental Information* and Note 13, *Subsequent Events,* for additional information regarding the placement of $1.05 billion of the proceeds in a qualified trust to facilitate an anticipated like-kind-exchange transaction for federal income tax purposes.

June 2012 Acquisition of Reserves in the Gulf Coast region at Thompson Field. In June 2012, we acquired a nearly 100% working interest and 84.7% net revenue interest in Thompson Field for $366.2 million after preliminary closing adjustments. The field is located approximately 18 miles west of Hastings Field, which is an enhanced oil recovery field that we are currently flooding with CO_2, and is the current terminus of the Green Pipeline which transports CO_2 from the Jackson Dome, located near Jackson, Mississippi. Thompson Field is similar to Hastings Field, producing oil from the Frio zone at similar depths, and is also a planned future tertiary field. Under the terms of the Thompson Field acquisition agreement, the seller will retain approximately a 5% gross revenue interest (less severance taxes) once average monthly oil production exceeds 3,000 Bbls/d after the initiation of CO_2 injection.

This acquisition meets the definition of a business under the FASC *Business Combinations* topic. As such, we estimated the fair value of assets acquired and liabilities assumed as of June 1, 2012, the closing date of the acquisition using a discounted future net cash flow model. In applying these accounting principles, we estimated the fair value of the assets acquired less liabilities assumed on the acquisition date to be approximately $318.9 million. This measurement resulted in the recognition of goodwill of approximately $47.3 million, which represents the excess of the cash paid to acquire the field over the acquisition date estimated fair value. This resultant goodwill is due primarily to two factors. The first factor is the decrease in average NYMEX oil futures prices between the date of signing the purchase agreement on April 24, 2012 and closing the purchase on June 1, 2012. The second factor is the fair value assigned to the estimated oil reserves recoverable through a CO_2 EOR project. By building an 18-mile extension of the Green Pipeline, we will have access to CO_2 reserves at Jackson Dome, one of the few known significant natural sources of CO_2 in the United States, and the largest known source east of the Mississippi River, allowing us to carry out CO_2 EOR activities in this field at a lower cost than other market participants. However, the FASC *Fair Value Measurements and Disclosures* topic does not allow entity-specific assumptions in the measurement of fair value. Therefore, we estimated the fair value of the oil reserves recoverable through CO_2 EOR using a higher estimated cost of CO_2 to other market participants, which lowers the discounted net revenue stream used in making the fair value estimate related to this field. All of the goodwill associated with the acquisition is deductible for tax purposes as property cost.

The fair value of the assets acquired and liabilities assumed was finalized during the fourth quarter of 2012, after consideration of final closing adjustments and evaluation of reserves and asset retirement obligations. The following table presents a summary of the fair value of assets acquired and liabilities assumed in the Thompson Field acquisition:

In thousands	
Consideration:	
Cash payment [(1)]	$366,179
Less: Fair value of assets acquired and liabilities assumed:	
Oil and natural gas properties	
Proved	305,233
Unevaluated	12,023
Pipelines and plants	2,000
Other assets	2,957
Asset retirement obligations	(3,306)
	318,907
Goodwill	$ 47,272

(1) See Note 6, *Income Taxes,* for additional information regarding the like-kind-exchange transaction utilized to fund this purchase and Note 12, *Supplemental Information,* for supplemental cash flow information regarding the cash payment.

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 CO_2 resources. The purchase included a 42.5% interest in a gas plant, currently under construction, which will separate the helium and natural gas from the commingled gas stream, and interests in certain surrounding properties. On August 1, 2011, we acquired the remaining 57.5% working interest in Riley Ridge that we did not already own, the remaining 57.5% interest in the gas plant, and interests in certain surrounding properties for $214.8 million after closing adjustments. As a result of the transaction, we became the operator of both projects. The purchase price includes a $15 million deferred payment to be made, subject to the terms of the purchase agreement, at the time the property's gas plant is operational and meets specific performance conditions. This deferred payment is measured at fair value on a quarterly basis using management's expectation of future cash flows. 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.

Each of the acquisitions of Riley Ridge meets the definition of a business under the FASC *Business Combinations* topic. As such, we estimated the fair value of assets acquired and liabilities assumed using a discounted net cash flow model. Goodwill associated with the acquisitions is deductible for income tax purposes. The fair values assigned to assets acquired and liabilities assumed in the August 2011 acquisition have been finalized, and no adjustments have been made to fair value amounts previously disclosed in our Form 10-K for the period ended December 31, 2011. The following table presents a summary of the fair value of assets acquired and liabilities assumed in the August 2011 Riley Ridge acquisition:

In thousands	
Consideration:	
Cash payment	$199,779
Deferred payment	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
CO_2 properties	9,741
Pipelines and plants	91,594
Other assets (1)	48,660
Asset retirement obligations	(389)
	210,879
Goodwill	$ 3,900

(1) 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 our 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 unit-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.

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, which we issued in February 2010, borrowings under a new $1.6 billion revolving credit agreement entered into in March 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 March 9, 2010, the acquisition date, which was the date on which we obtained control of Encore.

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 were 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.

Unaudited Pro Forma Acquisition Information. The following combined pro forma total revenues and other income and net income are presented as if the Bakken Exchange Transaction and Thompson Field acquisition had occurred on January 1, 2011:

	Year Ended December 31,	
In thousands, except per share data	2012	2011
Pro forma total revenues and other income	$2,203,703	$2,184,507
Pro forma net income	454,549	523,227
Pro forma net income per common share		
Basic	$ 1.18	$ 1.32
Diluted	1.17	1.30

The following combined pro forma total revenues and other income and net income attributable to Denbury stockholders are presented as if the acquisition of Encore occurred on January 1, 2010:

In thousands, except per share data	Year Ended December 31, 2010
Pro forma total revenues and other income	$2,098,241
Pro forma net income attributable to Denbury stockholders	286,891
Pro forma net income per common share	
Basic	$ 0.73
Diluted	0.72

Divestitures

2012 Divestitures. In April 2012, we completed the sale of certain non-operated assets in the Paradox Basin of Utah for $75.0 million. The sale had an effective date of January 1, 2012, and proceeds received after consideration of final closing adjustments totaled $68.5 million. Closing adjustments included operating net revenues after January 1, 2012, net of capital and lease operating expenditures, along with other purchase price adjustments. We did not record a gain or loss on the sale in accordance with the full cost method of accounting.

In February 2012, we completed the sale of certain non-core assets primarily located in central and southern Mississippi and in southern Louisiana for $155.0 million to a privately held entity in which a member of our Board of Directors served as chairman of the board, in a sale for which there was a competing bid contained in a multi-property purchase proposal. We realized net proceeds of $141.8 million, after final closing adjustments. The sale had an effective date of December 1, 2011, and consequently, operating revenues of $13.5 million after the effective date, net of capital and lease operating expenditures, along with any other purchase price adjustments, were adjustments to the selling price. We did not record a gain or loss on the sale in accordance with the full cost method of accounting.

Certain of our 2012 divestitures were structured as like-kind-exchange transactions for federal income tax purposes. See Note 6, *Income Taxes* for further details.

2010 Divestitures. In December 2010, we sold our ownership interests in ENP, which consisted of our 100% ownership in ENP 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 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.

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. Together with the sale of our ownership interest in ENP and ENP GP LLC discussed above, 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.

In February 2010, we sold our interest in Genesis Energy, LLC, the general partner of Genesis Energy, L.P. ("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 accounted for our investment in Genesis under the equity method, and we recognized a pre-tax gain of approximately $101.5 million ($63.0 million after tax) on these dispositions.

Note 3. Asset Retirement Obligations

The following table summarizes the changes in our asset retirement obligations for the years ended December 31, 2012 and 2011:

	Year Ended December 31,	
In thousands	2012	2011
Beginning asset retirement obligation	$ 93,468	$ 85,744
Liabilities incurred and assumed during period	50,956	12,477
Revisions in estimated retirement obligations	5,334	12,217
Liabilities settled and sold during period	(50,556)	(23,257)
Accretion expense	7,228	6,287
Ending asset retirement obligation	106,430	93,468
Less: current asset retirement obligation (1)	(3,700)	(4,742)
Long-term asset retirement obligation	$ 102,730	$ 88,726

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

Liabilities incurred and assumed generally relate to the drilling of incremental wells and liabilities assumed upon the acquisition of Thompson, Webster and Hartzog Draw fields during 2012. Liabilities settled include the plugging of old wells in the Tinsley Field during 2012 and 2011. Sales of properties in 2012 primarily represent the sale of non-core assets located in the Paradox Basin of Utah, Gulf Coast region and Bakken area assets in North Dakota and Montana.

We have escrow accounts that are legally restricted for certain of our asset retirement obligations. The balances of these escrow accounts were $35.2 million and $34.1 million at December 31, 2012 and 2011, 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 approximate cost at December 31, 2012 and 2011.

Note 4. Property and Equipment

The following table presents a summary of our net property and equipment balances as of December 31, 2012 and 2011:

In thousands	December 31, 2012	2011
Oil and natural gas properties		
Proved properties	$ 6,963,211	$ 7,026,579
Unevaluated properties	809,154	1,157,106
Total	7,772,365	8,183,685
Accumulated depletion and depreciation	(2,827,256)	(2,407,520)
Net oil and natural gas properties	4,945,109	5,776,165
CO_2 properties		
CO_2 properties	1,032,653	596,003
Accumulated depletion and depreciation	(119,784)	(91,666)
Net CO_2 properties	912,869	504,337
Pipelines and plants		
CO_2 pipelines (1)	1,632,255	1,432,646
Plants under construction (2)	402,871	269,110
Total	2,035,126	1,701,756
Accumulated depletion and depreciation	(99,185)	(65,392)
Net plants and pipelines	1,935,941	1,636,364
Other property and equipment		
Other property and equipment	417,207	157,674
Accumulated depletion and depreciation	(134,016)	(62,915)
Net other property and equipment	283,191	94,759
Net property and equipment	$ 8,077,110	$ 8,011,625

(1) Amounts include $346.5 million of CO_2 pipelines at December 31, 2012 that were not subject to depreciation during 2012.

(2) Plants under construction are not subject to depreciation.

A summary of the unevaluated properties excluded from oil and natural gas properties being amortized at December 31, 2012, and the year in which they were incurred follows:

	December 31, 2012				
	Costs Incurred During:				
In thousands	2012	2011	2010	2009 and Prior	Total
Property acquisition costs	$110,658	$12,543	$351,712	$115,075	$589,988
Exploration and development	106,075	40,152	3,155	8,390	157,772
Capitalized interest	29,249	30,430	333	1,382	61,394
Total	$245,982	$83,125	$355,200	$124,847	$809,154

Our 2012 property acquisition costs were primarily related to the fair value allocated to our Hartzog Draw and Thompson fields. Our 2010 property acquisition costs were primarily related to the fair value allocated to CO_2 tertiary potential at our Bell Creek and Cedar Creek Anticline properties, acquired as part of the Encore Merger. Property acquisition costs for 2009 and prior were primarily related to CO_2 tertiary potential at Conroe Field. Exploration and development costs shown as unevaluated properties are primarily associated with our tertiary oil fields that are under development but did not have proved reserves at December 31, 2012. The most significant development costs incurred during 2012 and 2011 relate to development in preparation for upcoming CO_2 floods at Bell Creek and Grieve fields. We have not yet recognized proved reserves in these fields.

During 2012, we established proved reserves at Hastings and Oyster Bayou fields and, as a result, transferred $431.1 million of costs incurred on these projects 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, 2012 and 2011:

	December 31,	
In thousands	2012	2011
Bank Credit Agreement	$ 700,000	$ 385,000
9½% Senior Subordinated Notes due 2016, including premium of $9,118 and $11,854, respectively	234,038	236,774
9¾% Senior Subordinated Notes due 2016, including discount of $13,569 and $17,854, respectively	412,781	408,496
8¼% Senior Subordinated Notes due 2020	996,273	996,273
6⅜% Senior Subordinated Notes due 2021	400,000	400,000
Other Subordinated Notes, including premium of $25 and $33, respectively	3,832	3,840
Pipeline financings	236,244	243,274
Capital lease obligations	158,260	4,388
Total	3,141,428	2,678,045
Less: current obligations	(36,966)	(8,316)
Long-term debt and capital lease obligations	$3,104,462	$2,669,729

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 of such notes is 100% owned, directly or indirectly, by DRI; any subsidiaries of DRI other than the subsidiary guarantors are minor subsidiaries, and the guarantees of the notes are full and unconditional and joint and several.

February 2013 Issuance of 4⅝% Senior Subordinated Notes due 2023

On February 5, 2013, we issued $1.2 billion of 4⅝% Senior Subordinated Notes due 2023 (the "2023 Notes"). The 2023 Notes, which carry a coupon rate of 4.625%, were sold at par. We intend to use the net proceeds of $1.18 billion from the issuance of the 2023 Notes to repurchase or redeem our 9½% Senior Subordinated Notes due 2016 (the "9½% Notes") and our 9¾% Senior Subordinated Notes due 2016 (the "9¾% Notes") and to pay down a portion of outstanding borrowings on our Bank Credit Agreement. See Note 13, *Subsequent Events,* for more information.

$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 party thereto (as amended, 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 2012 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 $1.2 billion 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. During 2012, we received a limited waiver of any oil hedging noncompliance that may occur as a result of the Bakken Exchange Transaction during the period commencing on the closing date continuing through and including December 31, 2013 (see Note 2, *Acquisitions and Divestitures*).

Under the Bank Credit Agreement, we are permitted to incur capital lease obligations in an aggregate amount outstanding at any time not to exceed $300 million, and are also permitted to incur up to $40 million of other unsecured debt (which include capital leases). The Bank Credit Agreement was amended during 2012 concurrent with our change in classification of equipment leases from operating to capital (see *Capital Leases* below), and we received a waiver of any applicable violations of the provisions of the Bank Credit Agreement resulting from such correction and the recording of our equipment leases as debt.

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 in a range from 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 in a range from 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 (as defined in the Bank Credit Agreement) 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 to the borrowing base, on the unused availability under the Bank Credit Agreement.

2011 Redemption of our 2013 and 2015 Notes

Pursuant to cash tender offers, during March 2011, we repurchased $169.6 million in principal of our 7½% Senior Subordinated Notes due 2013 (the "2013 Notes") at 100.625% of par, and $220.9 million in principal of our 7½% Senior Subordinated Notes due 2015 (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 Consolidated Statements of Operations under the caption "Loss on early extinguishment of debt".

9½% Senior Subordinated Notes due 2016

As a result of the Encore Merger, we 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 9½%. 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. 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 indenture governing the 9½% Notes includes various covenants and restrictions, including providing a put right by holders upon a change of control. All of our subsidiaries, other than minor subsidiaries, guarantee this debt jointly and severally. Pursuant to a cash tender offer commenced during January 2013, during February 2013 we repurchased $186.7 million principal amount of our 9½% Notes at 106.87% of par, and the indenture governing the 9½% Notes was amended to eliminate most of its restrictive covenants and certain events of default. We intend to use a portion of the net proceeds from the recent issuance of our 2023 Notes to fund the redemption of the remaining outstanding principal amount of our 9½% Notes. See Note 13, *Subsequent Events,* for more information.

9¾% Senior Subordinated Notes due 2016

In February 2009, we issued $420.0 million of 9¾% Notes, which carry a coupon rate of 9.75%. The 9¾% Notes 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 $6.4 million of 9¾% Notes.

The 9¾% Notes mature on March 1, 2016, and interest on the 9¾% Notes is payable March 1 and September 1 of each year. The indenture governing the 9¾% 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 9¾% Notes are not subject to any sinking fund requirements. All of our subsidiaries, other than minor subsidiaries, guarantee this debt jointly and severally. Pursuant to a cash tender offer commenced during January 2013, during February 2013 we repurchased $191.7 million principal amount of our 9¾% Notes at 105.425% of par. On February 5, 2013, we called the remaining 9¾% Notes for redemption on March 7, 2013, at 104.875% of par. See Note 13, *Subsequent Events,* for more information.

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.

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. 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.

6⅜% Senior Subordinated Notes due 2021

In February 2011, we issued $400 million of 6⅜% 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 *Redemption of our 2013 and 2015 Notes* above). The 2021 Notes mature on August 15, 2021, and interest is payable on February 15 and August 15 of each year. 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.

Pipeline Financings

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.

Debt Issuance Costs

In connection with the issuance of our outstanding long-term debt, we have incurred debt issuance costs, which are being amortized to interest expense using the effective interest method over the term of each related facility. Remaining unamortized debt issuance costs were $56.5 million and $69.6 million at December 31, 2012 and 2011, respectively. These balances are included in "Other assets" in our Consolidated Balance Sheets.

Indebtedness Repayment Schedule

At December 31, 2012, 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	
2013	$ 36,966
2014	38,481
2015	39,113
2016	1,388,592
2017	34,965
Thereafter	1,607,737
Total indebtedness	$3,145,854

Capital Lease Obligations

During the second quarter of 2012, we corrected the accounting for our equipment leases from operating leases to capital leases to comply with the FASC *Leases* topic, as a result of the consideration of nonperformance-related default covenants included in our equipment lease agreements. We recorded a cumulative adjustment to establish the capital lease assets as “Other property and equipment” ($155.6 million) and the capital lease obligations as “Long-term debt” ($138.9 million) and “Current maturities of long-term debt” ($25.1 million) on the accompanying Consolidated Balance Sheets for the year ended December 31, 2012. We also recognized the cumulative pre-tax impact of $8.4 million ($5.2 million after tax) as “Other expenses” on the accompanying Consolidated Statements of Operations for the year ended December 31, 2012. Because the amounts involved were not material to our financial statements in any individual prior period and the cumulative impact is not material to the results of operations for the year ended December 31, 2012, we recorded the cumulative effect of correcting these items during 2012.

Note 6. Income Taxes

Our income tax provision (benefit) is as follows:

	Year Ended December 31,		
In thousands	2012	2011	2010
Current income tax expense (benefit)			
Federal	$ 57,720	$ (12,552)	$ 15,683
State	18,034	20,801	17,511
Total current income tax expense	75,754	8,249	33,194
Deferred income tax expense			
Federal	239,862	329,715	143,381
State	15,881	12,748	16,968
Total deferred income tax expense	255,743	342,463	160,349
Total income tax expense	$331,497	$350,712	$193,543

During 2012, for federal income tax purposes, we structured the divestitures of our Bakken area assets and certain non-core assets as like-kind-exchange transactions for interests acquired in Thompson, Webster, Hartzog Draw and LaBarge fields and assets to be acquired in the Pending CCA Acquisition (See Note 13, *Subsequent Events*), thereby deferring the majority of the taxable gain on those divestitures. The increase in current taxes during 2012 is primarily due to the taxable gain recognized in the Bakken Exchange Transaction that we were unable to defer through a like-kind-exchange transaction.

At December 31, 2012, we had tax-effected state net operating loss carryforwards (“NOLs”) totaling $35.0 million, an estimated $17.3 million of enhanced oil recovery credits to carry forward related to our tertiary operations, and $34.8 million of alternative minimum tax credits. Our state NOLs expire in various years, starting in 2015, although most do not begin to expire until 2024. Our enhanced oil recovery credits will begin to expire in 2025.

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, 2012 and 2011 balance sheet dates. We believe that we will be able to realize all of our deferred tax assets at December 31, 2012, and therefore, have provided no valuation allowance against our deferred tax assets.

Significant components of our deferred tax assets and liabilities as of December 31, 2012 and 2011 are as follows:

	December 31,	
In thousands	2012	2011
Deferred tax assets:		
Loss carryforwards – federal	$ —	$ 13,970
Loss carryforwards – state	35,007	41,960
Tax credit carryover	34,837	34,829
Derivative contracts	7,252	3,551
Enhanced oil recovery credit carryforwards	17,346	53,381
Stock based compensation	28,387	32,566
Other	37,226	35,279
Total deferred tax assets	160,055	215,536
Deferred tax liabilities:		
Property and equipment	(2,277,388)	(2,078,143)
Other	(6,963)	(5,813)
Total deferred tax liabilities	(2,284,351)	(2,083,956)
Total net deferred tax liability	$(2,124,296)	$(1,868,420)

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

	Year Ended December 31,		
In thousands	2012	2011	2010
Income tax provision calculated using the federal statutory income tax rate	$ 299,900	$ 323,416	$ 167,674
State income taxes, net of federal income tax benefit	30,955	29,555	13,087
Effect of statutory rate change	(429)	(578)	11,502
Other	1,071	(1,681)	1,280
Total income tax expense	$ 331,497	$ 350,712	$ 193,543

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. 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. 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. Refund claims of $10.6 million for tax years through 2006 were received, plus accrued interest, in 2012.

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 our 2006, 2007 and 2008 tax years during the fourth quarter of 2011 with no adjustments. During the third quarter of 2012, the IRS concluded its audit of Encore Acquisition Company for the tax years 2008, 2009 and 2010 and Encore Operating LP for the tax years 2008 and 2009, with no significant adjustments. During the fourth quarter of 2012, the state of Mississippi concluded its audit of Denbury for the tax years 2004, 2005, 2006, and 2007, with no significant adjustments. Our income tax returns for tax years ending 2009 through 2011 currently remain subject to examination by the appropriate taxing authorities. We have not paid any significant interest or penalties associated with our income taxes.

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. During 2012, the Board of Directors increased the dollar amount of Denbury common shares that can be purchased under the program to an aggregate of $771.2 million. 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. During 2012, we repurchased 17.0 million shares of Denbury common stock for $266.7 million, or $15.71 per share, and during 2011, we repurchased 14.1 million shares of Denbury common stock for $195.2 million, or $13.83 per share under this share repurchase program. From the time the share repurchase program commenced in October 2011 through December 31, 2012, we have purchased 31.1 million shares of Denbury common stock (approximately 7.7% of our outstanding shares of common stock at September 30, 2011) at a cost of $461.9 million, and at that date, we were authorized to spend an additional $309.3 million under this repurchase program. We account for treasury stock using the cost method and include treasury stock as a component of stockholders' equity. See Note 13, *Subsequent Events,* for additional information.

Other share repurchases during 2012 and 2011, and all of our share repurchases during 2010 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, 2012, there were 462,131 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 $5.7 million, $4.8 million and $3.5 million for the years ended December 31, 2012, 2011 and 2010, 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 2012, 2011 and 2010, our matching contributions to the 401(k) Plan were approximately $8.0 million, $7.1 million and $5.7 million, respectively.

Note 8. Stock Compensation Plans

Stock Incentive Plans

We have two stock compensation plans. The first plan (providing only for the issuance of stock options) has been in existence since 1995 (the "1995 Plan") and expired in August 2005 (although options granted under the 1995 Plan prior to that time can remain outstanding for up to 10 years). The second plan, the 2004 Omnibus Stock and Incentive Plan (the "2004 Plan"), 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, restricted stock units, 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 have been authorized for issuance pursuant to the 2004 Plan. At December 31, 2012, 11.3 million shares were available under the 2004 Plan for future issuance of awards, all of which could be issued in the form of restricted stock or performance 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 three- or four-year vesting period, with the specific terms of vesting determined at the time of grant based on guidelines established by the Compensation Committee of the Board of Directors. The stock options and SARs expire over terms not to exceed 10 years from the date of grant, 90 days after termination of employment, 90 days or one year after permanent disability, depending on the plan, or one year after the death of the optionee. The stock options and SARs are granted 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.

Holders of restricted stock awards have the rights and privileges of owning the shares (including voting rights) except that the holders are not entitled to delivery of a portion thereof until certain requirements are met. Restricted stock awards vest over three-to-four-year vesting periods, with the specific terms of vesting determined at the time of grant.

Annually, the Board of Directors grants performance-based equity awards to officers of Denbury. These performance-based awards vest over 1.25 to 3.25 years and the number of performance-based shares earned (and eligible to vest) during the performance period will depend upon two sets of factors: (1) our level of success in achieving four specifically identified performance targets ("Performance-based Operational Awards") and (2) relative performance of our stock to that of a designated peer group ("Performance-based TSR Awards"). Generally, one-half of the maximum number of shares that could be earned under the performance-based awards will be earned for performance at the designated target levels (100% target vesting levels) or upon any earlier change of control, and twice the 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. Performance-based Operational Awards are valued using the fair market value of Denbury stock on the grant date and Performance-based TSR Awards are valued using a Monte Carlo simulation.

Stock-based compensation expense associated with our field employees is included in "Lease operating expense," while such expense associated with non-field employees is included in "General and administrative expenses" in the Consolidated Statements of Operations. Stock-based compensation associated with 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, 2012, 2011 and 2010, are as follows:

	Year Ended December 31,		
In thousands	2012	2011	2010
Stock-based compensation expensed:			
General and administrative expenses	$26,463	$30,256	$28,169
Lease operating expenses	2,847	2,621	2,056
Transaction and other costs related to the Encore Merger	—	313	5,866
Total stock-based compensation expensed	29,310	33,190	36,091
Stock-based compensation capitalized	8,587	6,998	3,702
Total cost of stock-based compensation arrangements	$37,897	$40,188	$39,793
Income tax benefit realized for stock-based compensation arrangements	$15,131	$18,383	$ 8,462

Stock Options and SARs

The fair value of each SARs 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 common 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 have historically not paid dividends.

	2012	2011	2010
Weighted average fair value of SARs granted	$8.90	$9.68	$8.45
Risk-free interest rate	0.79%	1.74%	2.19%
Expected life	4.0 to 5.0 years	4.0 to 5.0 years	4.0 to 4.3 years
Expected volatility	64.9%	63.3%	65.0%
Dividend yield	—	—	—

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

	Number of Awards	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at December 31, 2011	11,949,610	$13.56		
Granted	1,066,294	17.14		
Exercised	(2,029,570)	8.03		
Forfeited or expired	(541,199)	18.34		
Outstanding at December 31, 2012	10,445,135	14.75	3.7	$31,861
Exercisable at end of period	7,115,744	$13.81	3.2	$30,031

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

	Year Ended December 31,		
In thousands	2012	2011	2010
Intrinsic value of stock options exercised	$ 17,315	$20,463	$12,670
Grant-date fair value of stock options and SARs vested	26,391	11,416	8,689

As of December 31, 2012, there was $13.8 million of total compensation cost to be recognized in future periods related to nonvested stock option and SARs share-based compensation arrangements. The cost is expected to be recognized over a weighted-average period of 2.0 years. The following is a summary of cash received from stock option exercises under share-based payment arrangements and tax benefits realized from the exercises of stock options and SARs:

	Year Ended December 31,		
In thousands	2012	2011	2010
Cash received from stock option exercises	$ 6,022	$4,685	$4,867
Tax benefit realized for the exercises of stock options and SARs	241	879	4,603

Restricted Stock – 2004 Plan

As of December 31, 2012, there was $29.0 million of unrecognized compensation expense related to nonvested restricted stock grants. This unrecognized compensation cost is expected to be recognized over a weighted-average period of 2.61 years. The following is a summary of the total vesting date fair value of restricted stock under the 2004 Plan:

	Year Ended December 31,		
In thousands	2012	2011	2010
Fair value of restricted stock vested	$22,332	$12,355	$12,731

A summary of the status of our nonvested restricted stock grants issued under our 2004 Plan and the changes during the year ended December 31, 2012 is presented below:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at December 31, 2011	3,131,435	$14.82
Granted	1,909,739	16.94
Vested	(1,378,496)	15.38
Forfeited	(256,471)	17.08
Nonvested at December 31, 2012	3,406,207	15.60

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, 2012, there was $0.5 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 1.1 years. The following is a summary of the total vesting date fair value of restricted stock under the Encore Plan:

	Year Ended December 31,		
In thousands	2012	2011	2010
Fair value of restricted stock vested	$584	$2,259	$6,571

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, 2012 is presented below:

	Shares	Weighted Average Grant-Date Fair Value
Nonvested at December 31, 2011	103,043	$15.43
Vested	(36,049)	15.43
Forfeited	(10,736)	15.43
Nonvested at December 31, 2012	56,258	15.43

Performance-Based Equity Awards

During 2012, we granted Performance-based Operational Awards and Performance-based TSR Awards to our officers. The range of assumptions used in the Monte Carlo simulation valuation approach for Performance-based TSR Awards, which were granted for the first time during 2012, are as follows:

	2012
Weighted average fair value of Performance-based TSR Award granted	$24.68
Risk-free interest rate	0.42%
Expected life	2.81 years
Expected volatility	45.2%
Dividend yield	—

A summary of the status of the nonvested performance-based equity awards (presented at the target level) during the year ended December 31, 2012 is as follows:

	Performance-based Operational Awards		Performance-based TSR Awards	
	Number of Awards	Weighted Average Grant-Date Fair Value	Number of Awards	Weighted Average Grant-Date Fair Value
Nonvested at December 31, 2011	214,627	$18.71	—	$ —
Granted	110,615	17.27	96,325	24.68
Vested (1)	(214,627)	18.71	—	—
Forfeited	(10,422)	17.27	(9,408)	24.68
Nonvested at December 31, 2012	100,193	17.27	86,917	24.68

(1) During 2012, the 2011 annual Performance-based Operational Awards vested, and award holders received shares equivalent to 56% of the number of target-level shares.

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

In thousands	Year Ended December 31, 2012	2011	2010
Vesting date fair value of Performance-based Operational Awards	$ 2,191	$10,892	$7,532

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.

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 two years in the future from the current quarter, 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. We do not have any natural gas derivative contracts for 2013 or beyond. Because our current and forecasted production is primarily oil, we currently use only oil derivative contracts in our commodity market risk management program.

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

In thousands	Year Ended December 31, 2012	2011	2010
Oil			
Payment on settlements of derivative contracts	$ 9,991	$ 25,128	$ 93,417
Fair value adjustments to derivative contracts – income	(10,904)	(58,980)	(44,441)
Total derivatives expense (income) – oil	(913)	(33,852)	48,976
Natural gas			
Receipt on settlements of derivative contracts	(27,871)	(27,505)	(61,805)
Fair value adjustments to derivative contracts – expense (income)	23,950	8,860	(8,585)
Total derivatives expense (income) – natural gas	(3,921)	(18,645)	(70,390)
Ineffectiveness on interest rate swaps	—	—	(2,419)
Derivatives expense (income)	$ (4,834)	$ (52,497)	$ (23,833)

Commodity Derivative Contracts Not Classified as Hedging Instruments

				Contract Prices per Barrel		
					Weighted Average Price	
Year	Months	Type of Contract	Volume (Barrels per day)	Range	Floor	Ceiling
Oil contracts:						
2013	Jan – Mar	Collar	55,000	$70.00 – 113.00	$78.91	$108.01
	Apr – June	Collar	56,000	75.00 – 121.50	79.64	108.61
	July – Sept	Collar	56,000	75.00 – 133.10	79.64	109.15
	Oct – Dec	Collar	54,000	80.00 – 127.50	80.00	117.53
2014	Jan – Mar	Collar	52,000	$80.00 – 104.50	$80.00	$102.44
	Apr – June	Collar	52,000	80.00 – 104.50	80.00	102.44
	July – Sept	Collar	48,000	80.00 – 98.80	80.00	97.46
	Oct – Dec	Collar	48,000	80.00 – 98.80	80.00	97.46

Additional Disclosures about Derivative Instruments:

At December 31, 2012 and 2011, 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, 2012	2011
		In thousands	
Derivatives not designated as hedging instruments:			
Derivative assets			
Crude oil contracts	Derivative assets – current	$ 19,477	$ 23,452
Natural gas contracts	Derivative assets – current	—	23,950
Crude oil contracts	Derivative assets – long-term	36	29
Derivative liabilities			
Crude oil contracts	Derivative liabilities – current	(2,659)	(22,610)
Deferred premiums [1]	Derivative liabilities – current	(183)	(3,913)
Crude oil contracts	Derivative liabilities – long-term	(23,781)	(18,702)
Deferred premiums [1]	Derivative liabilities – long-term	—	(170)
Total derivatives not designated as hedging instruments		$ (7,110)	$ 2,036

(1) Deferred premiums payable relate to various oil floor contracts and are payable on a monthly basis through January 2013.

Note 10. Fair Value Measurements

The FASC Fair Value Measurements and Disclosures topic defines fair value as 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. Our 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. At December 31, 2011, instruments in this category also included non-exchange-traded natural gas derivatives swaps that were based on regional pricing other than NYMEX (i.e., Houston Ship Channel). Our basis swaps were 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 our credit quality for liability positions. We use multiple sources of third-party credit data in determining counterparty nonperformance risk, including credit default swaps.

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2012 and 2011:

	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, 2012				
Assets:				
Oil derivative contracts	$ —	$ 19,513	$ —	$ 19,513
Liabilities:				
Oil derivative contracts	—	(26,440)	—	(26,440)
Total	$ —	$ (6,927)	$ —	$ (6,927)
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

The following table summarizes the changes in the fair value of our Level 3 assets and liabilities for the years ended December 31, 2012 and 2011:

	December 31,	
In thousands	2012	2011
Fair value of Level 3 instruments, beginning of year	$ 23,950	$16,478
Unrealized gains on commodity derivative contracts included in earnings	3,921	13,384
Receipts on settlement of commodity derivative contracts	(27,871)	(5,912)
Fair value of Level 3 instruments, end of year	$ —	$23,950
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

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. Management's estimate of the fair market value of contingent consideration has not changed from the acquisition date to December 31, 2012; therefore, there has been no impact on the Consolidated Statements of Operations for the years ended December 31, 2012 and 2011.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

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

Other Fair Value Measurements

The carrying value of our 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. We use a market approach to determine fair value of our fixed-rate debt using observable market data. The fair values of our senior subordinated notes are based on quoted market prices. The estimated fair value of our total long-term debt as of December 31, 2012 and 2011, excluding pipeline financing and capital lease obligations, is $2,956.9 million and $2,638.2 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 2012 have terms up to thirteen years. Lease payments associated with operating leases were $33.6 million, $52.3 million and $42.4 million in 2012, 2011 and 2010, respectively. We have subleased part of the office space included in our operating leases for which we received approximately $2.7 million, $2.4 million and $0.5 million in 2012, 2011 and 2010, respectively. In addition, we expect to receive approximately $3.6 million for 2013 through 2016 under these sublease agreements.

The following table summarizes by year the remaining non-cancelable future payments under these leases as of December 31, 2012:

In thousands	Pipeline Financing Leases	Capital Leases	Operating Leases
2013	$ 30,817	$ 35,429	$ 10,656
2014	31,992	31,629	11,452
2015	32,591	30,139	12,300
2016	31,233	28,038	12,384
2017	30,678	22,052	12,720
Thereafter	296,226	31,806	80,562
Total minimum lease payments	453,537	179,093	$140,074
Less: Amount representing interest	(217,293)	(20,833)	
Present value of minimum lease payments	$ 236,244	$158,260	

Commitments

We have entered into long-term commitments to purchase CO_2 that are either non-cancelable or cancelable only upon the occurrence of specified future events. The commitments continue for up to 20 years. The price we will pay for CO_2 varies depending on the amount of CO_2 delivered and the price of oil. We anticipate the contracts will provide us with approximately 335 MMcf/d to 675 MMcf/d of CO_2 at a cost of approximately $95 million to $190 million per year, assuming a $100 per Bbl NYMEX oil price.

We are party to long-term contracts that require us to deliver CO_2 to our industrial CO_2 customers at various contracted prices, plus we have a CO_2 delivery obligation to Genesis related to three CO_2 volumetric production payments ("VPPs"). Based upon the maximum amounts deliverable as stated in the industrial contracts and the VPPs, we estimate that we may be obligated to deliver up to 327 Bcf of CO_2 to these customers over the next 14 years. 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, 2012, 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.

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. After the commencement date, the contract provides for the delivery of a minimum contracted quantity of helium, subject to adjustment after start-up of the Riley Ridge Plant, which if not supplied in accordance with the terms of the contract, may obligate us to compensate the third-party helium purchaser for the amount of the shortfall in an amount not to exceed $8.0 million per year.

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.

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, 2012, 2011 and 2010, two purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company LLC (39%, 43% and 46% in 2012, 2011 and 2010, respectively) and Plains Marketing LP (17%, 16% and 14% in 2012, 2011 and 2010, respectively).

Allowance for Doubtful Accounts

We record an allowance for doubtful accounts for receivables that we determine to be uncollectible based on the specific identification basis. The allowance for doubtful accounts, which is netted against "Trade and other receivables" on the Consolidated Balance Sheets, was $0.3 million at December 31, 2012 and 2011.

Accounts Payable and Accrued Liabilities

	December 31,	
In thousands	2012	2011
Accrued exploration and development costs	$109,939	$141,868
Accounts payable	86,051	99,444
Accrued interest	60,698	60,923
Accrued compensation	48,451	35,861
Accrued lease operating expenses	23,862	24,185
Taxes payable	27,523	13,455
Other	58,144	53,600
Total	$414,668	$429,336

Supplemental Cash Flow Information

In thousands	Year Ended December 31, 2012	2011	2010
Supplemental cash flow information:			
Cash paid for interest, expensed	$ 137,950	$137,259	$ 151,831
Cash paid for interest, capitalized	77,432	60,540	66,815
Cash paid for income taxes	99,194	45,912	17,960
Cash received from income tax refunds	(38,004)	(24,677)	(15,107)
Non-cash investing activities:			
Increase in asset retirement obligations	56,290	24,694	53,579
Increase (decrease) in liabilities for capital expenditures	(26,882)	74,697	(237)
Sale of non-core assets (1)	(212,544)	—	—
Purchase of Thompson Field (1)	212,544	—	—
Sale of Bakken area assets in Bakken Exchange Transaction (2)	(1,621,611)	—	—
Purchase of properties in Bakken Exchange Transaction (2)	571,596	—	—
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

(1) During 2012, $212.5 million of proceeds from the sale of certain non-core assets were paid by the purchaser directly to a qualified intermediary to facilitate a like-kind-exchange transaction for federal income tax purposes. The qualified intermediary subsequently released the funds to the previous owner of the Thompson Field to fund our acquisition of Thompson Field.

(2) During 2012, we sold our Bakken area assets with a fair value as determined in accordance with FASC rules of $1.9 billion to ExxonMobil in exchange for a combination of cash and various property interests valued in accordance with FASC rules at $571.6 million. ExxonMobil paid a portion of the cash proceeds ($1.05 billion) directly to a qualified intermediary to facilitate a like-kind-exchange transaction under federal income tax rules under which we expect our Pending CCA Acquisition to qualify (see Note 13, *Subsequent Events*). The remaining $281.7 million in cash proceeds are reported as an investing activity on our Statement of Cash Flows for the year ending December 31, 2012.

Note 13. Subsequent Events

Pending CCA Acquisition

In January 2013, we entered into an agreement to acquire producing assets in the Cedar Creek Anticline ("CCA") of Montana and North Dakota from a wholly-owned subsidiary of ConocoPhillips for $1.05 billion in cash, before standard closing adjustments primarily for revenues and costs of the properties to be purchased from the January 1, 2013 effective date to the closing date. We plan to fund the acquisition out of a portion of the cash proceeds from the Bakken Exchange Transaction in order to qualify the acquisition for like-kind-exchange treatment under federal income tax rules. We expect the acquisition to close near the end of the first quarter of 2013.

New Senior Subordinated Notes

On February 5, 2013, we issued the 2023 Notes, which carry a coupon rate of 4.625%, and were sold at par. The net proceeds of $1.18 billion have been used to repurchase a portion of, or are intended to be used to redeem the remainder of, our outstanding 9½% Notes and 9¾% Notes and to reduce borrowings under our credit facility.

The 2023 Notes mature on July 15, 2023, and interest is payable on January 15 and July 15 of each year, commencing July 15, 2013. We may redeem the 2023 Notes in whole or in part at our option beginning January 15, 2018, at the following redemption prices: 102.313% on or after January 15, 2018; 101.542% on or after January 15, 2019; 100.771% on or after January 15, 2020; and 100% on or after January 15, 2021. Prior to July 15, 2016, we may at our option redeem up to an aggregate of 35% of the principal amount of the 2023 Notes at a price of 104.625% with the proceeds of certain equity offerings. In addition, at any time prior to July 15, 2018, we may redeem 100% of the principal amount of the 2023 Notes at a price equal to 100% of the principal amounts plus a "make whole" premium and accrued and unpaid interest. The indenture contains certain restrictions on our ability to: (1) incur additional debt; (2) pay dividends on our common stock or redeem, repurchase or retire such capital stock or subordinated debt unless certain leverage ratios are met; (3) make investments; (4) create liens on our assets; (5) create restrictions on the ability of our restricted subsidiaries to pay dividends or make other payments to the Company; (6) engage in transactions with our affiliates; (7) transfer or sell assets; and (8) consolidate, merge or transfer all or substantially all of our assets and the assets of our subsidiaries. All of our significant subsidiaries fully and unconditionally guaranteed this debt.

Tender Offers

On January 22, 2013, we commenced cash tender offers to purchase $426.4 million principal amount of our 9¾% Notes and $224.9 million principal amount of our 9½% Notes. During February 2013, we accepted for purchase $191.7 million principal amount of the outstanding 9¾% Notes and $186.7 million principal amount of the outstanding 9½% Notes. We received sufficient consents in the solicitation to amend the indenture governing the 9½% Notes by entering into a supplemental indenture, which eliminated most of the restrictive covenants and certain events of default. The purchases under these tender offers were funded by the proceeds from the sale of our 2023 Notes. The tender offers expired on February 19, 2013. On February 5, 2013, we issued a notice of redemption for all remaining outstanding 9¾% Notes at 104.875% of par with a redemption date of March 7, 2013 and intend to call the 9½% Notes for redemption on or about May 1, 2013.

Stock Repurchase Program

Between January 1, 2013 and February 21, 2013, the Company repurchased an additional 3.5 million shares of Denbury common stock under the share repurchase program for $59.1 million, or $16.73 per share. From the time the share repurchase program commenced in October 2011 through February 21, 2013, we have repurchased a total of $521.0 million of common stock under the program, and are authorized to spend an additional $250.2 million under this repurchase program. See Note 7, *Stockholders' Equity,* for additional information.

Equity Award Grant

In January 2013, we granted equity incentive awards to our employees under the 2004 Plan. The grant included 1,545,077 shares of restricted stock valued at $16.77 per share (the closing price of Denbury's common stock on January 4, 2013) and 605,802 SARs with an exercise price of $16.77 and a weighted average grant date fair value ranging between $5.42 and $8.72 per unit. The awards generally vest 33% per year over a three-year period.

Note 14. 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 reserve costs, including the cost of drilling development wells, and to provide facilities for extracting, treating, gathering and storing the oil and natural gas, and the cost of improved recovery systems.

We capitalize interest on unevaluated oil and natural gas properties that have ongoing development activities. Included in costs incurred in the table below is capitalized interest of $36.5 million in 2012, $44.9 million in 2011 and $32.6 million in 2010. 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 $38.8 million in 2012, $24.2 million in 2011 and $45.1 million in 2010. 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	2012	2011	2010
Property acquisitions:			
Proved	$ 491,041	$ 86,465	$3,373,450
Unevaluated	115,270	17,858	1,297,695
Exploration	12,019	31,483	8,728
Development	1,111,314	1,144,243	658,758
Total costs incurred [1]	$ 1,729,644	$1,280,049	$5,338,631

(1) Capitalized general and administrative costs that directly relate to exploration and development activities were $49.2 million, $35.0 million and $20.1 million for the years ended December 31, 2012, 2011 and 2010, 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:

In thousands, except per BOE data	Year Ended December 31, 2012	2011	2010
Oil, natural gas, and related product sales	$2,409,867	$2,269,151	$1,793,292
Lease operating costs	532,359	507,397	470,364
Marketing expenses	52,836	26,047	31,036
Taxes other than income	149,919	138,419	114,569
Depletion, depreciation and amortization	448,424	369,075	391,782
CO_2 properties and pipelines depletion and depreciation [1]	42,064	24,460	29,206
Commodity derivatives expense (income)	(4,834)	(52,497)	(21,414)
Net operating income	1,189,099	1,256,250	777,749
Income tax provision	457,803	477,375	295,545
Results of operations from oil and natural gas producing activities	$ 731,296	$ 778,875	$ 482,204
Depletion, depreciation and amortization per BOE	$ 18.69	$ 16.42	$ 15.82

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

Oil and Natural Gas Reserves

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

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 2012, 2011 and 2010 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the applicable fiscal 12-month period. All of our reserves are located in the United States.

Estimated Quantities of Proved Reserves

	Year Ended December 31, 2012			2011			2010		
	Oil (MBbl)	Gas (MMcf)	Total (MBOE)	Oil (MBbl)	Gas (MMcf)	Total (MBOE)	Oil (MBbl)	Gas (MMcf)	Total (MBOE)
Balance at beginning of year	357,733	625,208	461,934	338,276	357,893	397,925	192,879	87,975	207,542
Revisions of previous estimates	(7,099)	(16,720)	(9,886)	(4,478)	(14,058)	(6,821)	3,538	16,171	6,233
Revisions due to price changes	(401)	(37,969)	(6,729)	2,558	485	2,639	2,780	811	2,915
Extensions and discoveries	14,910	10,005	16,579	42,936	52,339	51,658	26,313	130,245	48,021
Improved recovery [1]	69,543	—	69,543	264	—	264	30,173	—	30,173
Production	(24,462)	(10,654)	(26,238)	(22,169)	(10,783)	(23,966)	(21,870)	(28,491)	(26,619)
Acquisition of minerals in place	24,677	20,598	28,110	346	239,332	40,235	155,021	622,984	258,852
Sales of minerals in place	(105,777)	(108,827)	(123,915)	—	—	—	(50,558)	(471,802)	(129,192)
Balance at end of year	329,124	481,641	409,398	357,733	625,208	461,934	338,276	357,893	397,925
Proved Developed Reserves:									
Balance at beginning of year	239,741	125,970	260,736	219,077	110,516	237,496	116,192	69,513	127,778
Balance at end of year	236,009	64,191	246,708	239,741	125,970	260,736	219,077	110,516	237,496

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

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

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 initial acquisition of interests at Riley Ridge. 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, plus upward revisions to reserves in other tertiary floods.

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

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

Under the Standardized Measure, future cash inflows were estimated by applying a first-day-of-the-month 12-month average price to the estimated future production of year-end proved reserves. The product prices used 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,		
	2012	2011	2010
Oil (NYMEX)	$94.71	$96.19	$79.43
Natural Gas (Henry Hub)	2.85	4.16	4.40

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	2012	2011	2010
Future cash inflows	$ 34,779,549	$ 38,165,122	$26,698,819
Future production costs	(13,114,740)	(12,570,015)	(9,702,896)
Future development costs	(2,034,174)	(3,026,898)	(1,912,457)
Future income taxes	(6,672,857)	(7,379,972)	(4,700,023)
Future net cash flows	12,957,778	15,188,237	10,383,443
10% annual discount for estimated timing of cash flows	(6,543,398)	(8,180,632)	(5,465,516)
Standardized measure of discounted future net cash flows	$ 6,414,380	$ 7,007,605	$ 4,917,927

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:

In thousands	Year Ended December 31, 2012	2011	2010
Beginning of year	$ 7,007,605	$ 4,917,927	$ 2,457,385
Sales of oil and natural gas produced, net of production costs	(1,673,253)	(1,597,288)	(1,177,322)
Net changes in sales prices	(584,526)	4,646,086	2,062,181
Extensions and discoveries, less applicable future development and production costs	291,558	762,370	295,074
Improved recovery [1]	1,901,109	15,708	623,622
Previously estimated development costs incurred	376,199	354,228	193,947
Revisions of previous estimates, including revised estimates of development costs, reserves and rates of production	(797,975)	(1,673,283)	(285,158)
Accretion of discount	875,383	729,234	307,546
Acquisition of minerals in place	767,267	29,737	3,671,439
Sales of minerals in place	(1,805,309)	—	(1,474,443)
Net change in income taxes	56,322	(1,177,114)	(1,756,344)
End of year	$ 6,414,380	$ 7,007,605	$ 4,917,927

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

Note 15. Supplemental CO_2 and Helium Disclosures (Unaudited)

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

	Year Ended December 31, 2012	2011	2010
CO_2 reserves			
Gulf Coast region [1]	6,073,175	6,685,412	7,085,131
Rocky Mountain region [2]	3,495,534	2,195,534	2,189,756
Helium reserves associated with Denbury's production rights			
Rocky Mountain region [3]	12,712	12,004	7,159

(1) Proved CO_2 reserves in the Gulf Coast region consist of reserves from our reservoirs at Jackson Dome and are presented on a gross working interest (8/8ths) basis, of which our net revenue interest was approximately 4.8 Tcf, 5.3 Tcf and 5.6 Tcf at December 31, 2012, 2011 and 2010, respectively, and include reserves dedicated to volumetric production payments of 57.1 Bcf, 84.7 Bcf and 100.2 Bcf at December 31, 2012, 2011 and 2010, respectively.

(2) Proved CO_2 reserves in the Rocky Mountain region consist of our reserves at Riley Ridge (presented on a gross working interest (8/8ths) basis) and our overriding royalty interest in LaBarge Field, of which our net revenue interest was approximately 2.9 Tcf, 1.6 Tcf and 0.9 Tcf at December 31, 2012, 2011 and 2010, respectively.

(3) Reserves associated with helium production rights include helium reserves located in 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 16. Unaudited Quarterly Information

In thousands, except per share amounts	March 31	June 30	September 30	December 31
2012				
Revenues and other income	$ 645,116	$ 601,781	$ 600,371	$ 609,204
Derivatives expense (income)	45,275	(139,109)	61,631	27,369
Other expenses	420,529	398,089	399,361	386,470
Net income	113,467	211,865	85,367	114,661
Net income per share:				
Basic	0.29	0.55	0.22	0.30
Diluted	0.29	0.54	0.22	0.30
Cash flow provided by operating activities	291,654	440,966	293,506	384,765
Cash flow used for investing activities	(288,883)	(560,341)	(388,748)	(138,869)
Cash flow provided by (used for) financing activities	55,902	70,122	91,163	(118,676)
2011				
Revenues and other income	$ 514,165	$ 601,397	$ 576,505	$ 617,257
Derivatives expense (income)	170,750	(172,904)	(210,154)	159,811
Other expenses	366,361	350,499	343,339	377,577
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 provided by 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

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) was performed under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2012, to ensure: that information that is required to be disclosed in the reports the Company files and submits under the Securities Exchange Act of 1934 is recorded, that is processed, summarized and reported within the time periods specified in the SEC's rules and forms; and that information that is required to be disclosed under the Exchange Act is accumulated and communicated to management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Evaluation of Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we have determined that, during the fourth quarter of fiscal 2012, 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 our internal control over financial reporting as of December 31, 2012, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in the report that appears herein.

Important Considerations

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

Item 9B. Other Information

None.

Item 10. Directors, Executive Officers and Corporate Governance

Except as disclosed below, information as to Item 10 will be set forth in the Proxy Statement ("Proxy Statement") for the Annual Meeting of Shareholders to be held May 22, 2013 ("Annual Meeting") and is incorporated herein by reference.

Code of Ethics

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

Item 11. Executive Compensation

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

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

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

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

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

Item 14. Principal Accountant Fees and Services

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

Item 15. Exhibits and Financial Statement Schedules

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

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

Exhibit No.	Exhibit
2(a)	Agreement and Plan of Merger, dated as of October 31, 2009, by and between Encore Acquisition Company and Denbury Resources Inc. (incorporated by reference to Exhibit 2.1 of Form 8-K filed by the Company on November 5, 2009, File No. 001-12935).
2(b)	Exchange Agreement, dated as of September 19, 2012, by and among Denbury Onshore, LLC, XTO Energy Inc., and Exxon Mobil Corporation (incorporated by reference to Exhibit 2.1 of Form 8-K filed by the Company on September 25, 2012, File No. 001-12935).
2(c)	Closing Agreement and Amendment, dated as of November 30, 2012, by and among Denbury Onshore, LLC, XTO Energy Inc., and Exxon Mobil Corporation (incorporated by reference to Exhibit 2.2 of Form 8-K filed by the Company on December 6, 2012, File No. 001-12935).
2(d)	Second Closing Agreement and Amendment, dated as of December 21, 2012, by and among Denbury Onshore, LLC, XTO Energy Inc., and Exxon Mobil Corporation (incorporated by reference to Exhibit 2.1 of Form 8-K filed by the Company on December 26, 2012, File No. 001-12935).
2(e)	Purchase and Sale Agreement, dated as of January 14, 2013, by and between Burlington Resources Oil & Gas Company LP and Denbury Onshore, LLC (incorporated by reference to Exhibit 2.1 of Form 8-K filed by the Company on January 15, 2013, File No. 001-12935).
3(a)	Second Restated Certificate of Incorporation of Denbury Resources Inc. filed with the Delaware Secretary of State on August 21, 2012 (incorporated by reference to Exhibit 3(a) of Form 10-Q filed by the Company on November 8, 2012, File No. 001-12935).
3(b)	Amended and Restated Bylaws of Denbury Resources Inc. as of May 15, 2012 (incorporated by reference to Exhibit 3.2 of Form 8-K filed by the Company on May 21, 2012, File No. 001-12935).
4(a)	Indenture for 9.75% Senior Subordinated Notes due 2016, dated as of February 13, 2009, by and among Denbury Resources Inc., certain of its subsidiaries, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on February 17, 2009, File No. 001-12935).
4(b)	First Supplemental Indenture for 9.75% Senior Subordinated Notes due 2016, dated as of June 30, 2009, by and among Denbury Resources Inc., certain of its subsidiaries, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4(h) of Form 10-K filed by the Company on March 1, 2010, File No. 001-12935).
4(c)**	9.75% Senior Subordinated Note due 2016 issued on June 30, 2009 to Gareth Roberts (incorporated by reference to Exhibit 10.2 of Form 8-K filed by the Company on July 7, 2009, File No. 001-12935).
4(d)	Second Supplemental Indenture for 9.75% Senior Subordinated Notes due 2016, dated as of March 9, 2010, by and among Denbury Resources Inc., certain of its subsidiaries, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.6 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(e)	Third Supplemental Indenture for 9.75% Senior Subordinated Notes due 2016, dated as of February 3, 2011, by and among Denbury Resources Inc., certain of its subsidiaries, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4(p) of Form 10-K filed by the Company on March 1, 2011, File No. 001-12935).
4(f)	Indenture for 8¼% Senior Subordinated Notes due 2020, dated as of February 10, 2010, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on February 12, 2010, File No. 001-12935).

Exhibit No.	Exhibit
4(g)	First Supplemental Indenture for 8¼% Senior Subordinated Notes due 2020, dated as of March 9, 2010, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.7 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(h)	Second Supplemental Indenture for 8¼% Senior Subordinated Notes due 2020, dated as of February 3, 2011, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4(s) of Form 10-K filed by the Company on March 1, 2011, File No. 001-12935).
4(i)	Indenture for 6.25% Senior Subordinated Notes Due 2014, dated as of April 2, 2004, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1.1 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(j)	First Supplemental Indenture for 6.25% Senior Subordinated Notes Due 2014, dated as of January 2, 2008, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1.2 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(k)	Second Supplemental Indenture for 6.25% Senior Subordinated Notes Due 2014, dated as of January 27, 2010, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1.3 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(l)	Third Supplemental Indenture for 6.25% Senior Subordinated Notes Due 2014, dated as of March 10, 2010, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1.4 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(m)	Fourth Supplemental Indenture for 6.25% Senior Subordinated Notes Due 2014, dated as of February 3, 2011, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4(x) of Form 10-K filed by the Company on March 1, 2011, File No. 001-12935).
4(n)	Indenture for 6.0% Senior Subordinated Notes due 2015, dated as of July 13, 2005, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2.1 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(o)	First Supplemental Indenture for 6.0% Senior Subordinated Notes due 2015, dated as of January 2, 2008, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2.2 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(p)	Second Supplemental Indenture for 6.0% Senior Subordinated Notes due 2015, dated as of January 27, 2010, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2.3 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(q)	Third Supplemental Indenture for 6.0% Senior Subordinated Notes due 2015, dated as of March 10, 2010, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2.4 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(r)	Fourth Supplemental Indenture for 6.0% Senior Subordinated Notes due 2015, dated as of February 3, 2011, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4(cc) of Form 10-K filed by the Company on March 1, 2011, File No. 001-12935).

Exhibit No.	Exhibit
4(s)	Indenture for Subordinated Debt Securities, dated as of November 16, 2005, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3.1 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(t)	First Supplemental Indenture for 7.25% Senior Subordinated Notes due 2017, dated as of November 23, 2005, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3.2 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(u)	Second Supplemental Indenture for 7.25% Senior Subordinated Notes due 2017, dated as of January 2, 2008, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3.3 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(v)	Third Supplemental Indenture for 9.5% Senior Subordinated Notes due 2016, dated as of April 27, 2009, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3.4 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(w)	Fourth Supplemental Indenture for Senior Subordinated Notes, dated as of January 27, 2010, by and among Encore Acquisition Company, certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3.5 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(x)	Fifth Supplemental Indenture for Senior Subordinated Notes, dated as of March 10, 2010, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3.6 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
4(y)	Sixth Supplemental Indenture for Senior Subordinated Notes, dated as of February 3, 2011, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4(jj) of Form 10-K filed by the Company on March 1, 2011, File No. 001-12935).
4(z)	Seventh Supplemental Indenture for Senior Subordinated Notes, dated as of February 5, 2013, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 of Form 8-K filed by the Company on February 5, 2013, File No. 001-12935).
4(aa)	Indenture for 6 3/8% Senior Subordinated Notes due 2021, dated as of February 17, 2011, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee, (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on February 22, 2011, File No. 001-12935).
4(bb)	Indenture for 4 5/8% Senior Subordinated Notes due 2023, dated as of February 5, 2013, by and among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 of Form 8-K filed by the Company on February 5, 2013, File No. 001-12935).
10(a)	Credit Agreement, dated as of March 9, 2010, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on March 12, 2010, File No. 001-12935).
10(b)	First Amendment to Credit Agreement, dated as of May 13, 2010, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on May 19, 2010, File No. 001-12935).

Exhibit No.	Exhibit
10(c)	Second Amendment to Credit Agreement, dated as of September 30, 2010, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10.1 of Form 10-Q filed by the Company on November 9, 2010, File No. 001-12935).
10(d)	Third Amendment to Credit Agreement, dated as of December 17, 2010, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10(d) of Form 10-K filed by the Company on March 1, 2011, File No. 001-12935).
10(e)	Fourth Amendment to Credit Agreement, dated as of February 1, 2011, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10(e) of Form 10-K filed by the Company on March 1, 2011, File No. 001-12935).
10(f)	Fifth Amendment to Credit Agreement, dated as of May 19, 2011, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 99.1 of Form 8-K filed by the Company on May 20, 2011, File No. 001-12935).
10(g)	Sixth Amendment to Credit Agreement, dated as of September 1, 2011, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on September 8, 2011, File No. 001-12935).
10(h)	Seventh Amendment to Credit Agreement, dated as of April 11, 2012, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 4(a) of Form 10-Q filed by the Company on May 10, 2012, File No. 001-12935).
10(i)	Eighth Amendment to Credit Agreement, dated as of July 26, 2012, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 4(a) of Form 10-Q filed by the Company on August 8, 2012, File No. 001-12935).
10(j)	Ninth Amendment to Credit Agreement, dated as of November 2, 2012, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference to Exhibit 10(a) of Form 10-Q filed by the Company on November 8, 2012, File No. 001-12935).
10(k)*	Tenth Amendment to Credit Agreement, dated as of January 18, 2013, by and among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto.
10(l)	Pipeline Financing Lease Agreement, dated as of May 30, 2008, by and between Genesis NEJD Pipeline, LLC, as Lessor, and Denbury Onshore, LLC, as Lessee (incorporated by reference to Exhibit 99.1 of Form 8-K filed by the Company on June 5, 2008, File No. 001-12935).
10(m)	Transportation Services Agreement, dated as of May 30, 2008, by and between Genesis Free State Pipeline, LLC and Denbury Onshore, LLC (incorporated by reference to Exhibit 99.2 of Form 8-K filed by the Company on June 5, 2008, File No. 001-12935).
10(n)	Purchase and Sale Agreement, dated as of March 31, 2010, effective as of May 1, 2010, by and between Encore Operating, L.P., as Seller, and Quantum Resources Management, LLC, as Buyer (incorporated by reference to Exhibit 10.6 of Form 10-Q filed by the Company on May 10, 2010, File No. 001-12935).
10(o)**	Denbury Resources Inc. Amended and Restated Stock Option Plan, effective as of December 5, 2007 (incorporated by reference to Exhibit 99.2 of Form 8-K filed by the Company on December 11, 2007, File No. 001-12935).

Exhibit No.	Exhibit
10(p)**	Denbury Resources Inc. Amended and Restated Employee Stock Purchase Plan, effective as of December 5, 2007 (incorporated by reference to Exhibit 99.4 of Form 8-K filed by the Company on December 11, 2007, File No. 001-12935).
10(q)**	Denbury Resources Inc. Amendment to Amended and Restated Employee Stock Purchase Plan (incorporated by reference to Exhibit 4.2 of Registration Statement on Form S-8 filed by the Company on June 23, 2009, File No. 333-160178).
10(r)**	Denbury Resources Inc. Amendment to Amended and Restated Employee Stock Purchase Plan (incorporated by reference to Exhibit 4.2 of Post-Effective Amendment No. 1 to Form S-8 filed by the Company on September 9, 2009, File No. 333-160178).
10(s)**	Denbury Resources Inc. Amendment to Amended and Restated Employee Stock Purchase Plan, effective as of May 18, 2011 (incorporated by reference to Exhibit 4.1 of Registration Statement on Form S-8 filed by the Company on June 30, 2011, File No. 333-175273).
10(t)**	Form of Indemnification Agreement, dated as of July 28, 1999, by and between Denbury Resources Inc. and its officers and directors (incorporated by reference to Exhibit 10 of Form 10-Q filed by the Company on August 11, 1999, File No. 001-12935).
10(u)* **	Denbury Resources Inc. Director Deferred Compensation Plan, as amended and restated effective as of December 13, 2012.
10(v)* **	Denbury Resources Inc. Severance Protection Plan, as amended and restated effective as of December 13, 2012.
10(w)* **	Denbury Resources Inc. 2004 Omnibus Stock and Incentive Plan, as amended and restated on December 13, 2012.
10(x)**	2004 Form of Restricted Stock Award that vests on retirement for grants to officers pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(l) of Form 10-K filed by the Company on March 15, 2005, File No. 001-12935).
10(y)**	2009 Form of Restricted Stock Award to certain officers that cliff vests on March 31, 2012, pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(b) of Form 10-Q filed by the Company on May 11, 2009, File No. 001-12935).
10(z)**	2009 Form of Restricted Stock Award without change of control vesting to certain officers that cliff vests on March 31, 2012, pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(c) of Form 10-Q filed by the Company on May 11, 2009, File No. 001-12935).
10(aa)**	2009 Form of Performance Stock Award to certain officers pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(d) of Form 10-Q filed by the Company on May 11, 2009, File No. 001-12935).
10(bb)**	2009 Form of Performance Stock Award without change of control vesting to certain officers pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(e) of Form 10-Q filed by the Company on May 11, 2009, File No. 001-12935).
10(cc)**	2009 Form of Stock Appreciation Rights Agreement to certain officers that cliff vests on March 31, 2012 pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(f) of Form 10-Q filed by the Company on May 11, 2009, File No. 001-12935).
10(dd)**	2009 Form of Stock Appreciation Rights Agreement without change of control vesting pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 10(g) of Form 10-Q filed by the Company on May 11, 2009, File No. 001-12935).
10(ee)**	2010 Form of Performance Stock Award pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 99.2 of Form 8-K filed by the Company on May 25, 2010, File No. 001-12935).

Exhibit No.	Exhibit
10(ff)**	2010 Form of Performance Cash Award pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference to Exhibit 99.3 of Form 8-K filed by the Company on May 25, 2010, File No. 001-12935).
10(gg)**	Founder's Retirement Agreement, effective as of June 30, 2009, by and between Denbury Resources Inc. and Gareth Roberts (incorporated by reference to Exhibit 10.1 of Form 8-K filed by the Company on July 7, 2009, File No. 001-12935).
10(hh)**	Amendment to Founder's Retirement Agreement, effective as of October 6, 2010, by and between Denbury Resources Inc. and Gareth Roberts (incorporated by reference to Form 8-K filed by the Company on October 12, 2010, File No. 001-12935).
10(ii)**	2011 Form of Performance Stock Award pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(a) to Form 10-Q filed by the Company on May 10, 2011, File No. 001-12935).
10(jj)**	2011 Form of Performance Cash Award pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(b) to Form 10-Q filed by the Company on May 10, 2011, File No. 001-12935).
10(kk)**	Officer Resignation Agreement, effective as of October 7, 2011, by and between Denbury Resources Inc. and Ronald T. Evans (incorporated by reference to Exhibit 10.1 of Form 10-Q filed by the Company on November 8, 2011, File No. 001-12935).
10(ll)**	2012 Form of Performance Stock Award pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(a) of Form 10-Q filed by the Company on May 10, 2012, File No. 001-12935).
10(mm)**	2012 Form of Performance Cash Award pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(b) of Form 10-Q filed by the Company on May 10, 2012, File No. 001-12935).
10(nn)**	2012 Form of TSR Performance Award pursuant to the 2004 Omnibus Stock and Incentive Plan (incorporated by reference to Exhibit 10(c) of Form 10-Q filed by the Company on May 10, 2012, File No. 001-12935).
21*	List of subsidiaries of Denbury Resources Inc.
23(a)*	Consent of PricewaterhouseCoopers LLP.
23(b)*	Consent of DeGolyer and MacNaughton.
31(a)*	Certification of Chief Executive Officer Pursuant to Section 302 of Sarbanes-Oxley Act of 2002.
31(b)*	Certification of Chief Financial Officer Pursuant to Section 302 of Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99*	The summary of DeGolyer and MacNaughton's Report as of December 31, 2012, on oil and gas reserves (SEC Case) dated January 31, 2013.

* Filed herewith.

** Compensation arrangements.

Copies of the above exhibits not contained herein are available to any security holder upon request to the Secretary, Denbury Resources Inc., 5320 Legacy Drive, Plano, Texas 75024.

Exhibit 21

LIST OF SUBSIDIARIES

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

SIGNATURES

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

DENBURY RESOURCES INC.

/s/ Mark C. Allen February 28, 2013

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

/s/ Alan Rhoades February 28, 2013

Alan Rhoades
Vice President and Chief Accounting Officer

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

/s/ Phil Rykhoek February 28, 2013

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

/s/ Ron Greene February 28, 2013

Ron Greene
Director

/s/ Mark C. Allen February 28, 2013

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

/s/ Greg McMichael February 28, 2013

Greg McMichael
Director

/s/ Alan Rhoades February 28, 2013

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

/s/ Kevin Meyers February 28, 2013

Kevin Meyers
Director

/s/ Wieland Wettstein February 28, 2013

Wieland Wettstein
Director

/s/ Randy Stein February 28, 2013

Randy Stein
Director

/s/ Michael Beatty February 28, 2013

Michael Beatty
Director

/s/ Laura Sugg February 28, 2013

Laura Sugg
Director

/s/ Michael Decker February 28, 2013

Michael Decker
Director

Exhibit 23(a)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (Nos. 333-01006, 333-27995, 333-55999, 333-70485, 333-39172, 333-39218, 333-39224, 333-63198, 333-90398, 333-106253, 333-116249, 333-143848, 333-160178, 333-167480 and 333-175273) and Form S-3 (No. 333-186112) of Denbury Resources Inc. of our report dated February 28, 2013 relating to the consolidated financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Dallas, Texas
February 28, 2013

Exhibit 23(b)

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

February 27, 2013

DENBURY RESOURCES INC.
5320 Legacy Drive
Plano, Texas 75024

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to references to DeGolyer and MacNaughton, to the inclusion of our Letter Report dated January 31, 2013, regarding the proved reserves of Denbury Resources, and to the inclusion of information taken from our “Appraisal Report as of December 31, 2012 on Certain Properties owned by Denbury Resources Inc. SEC Case”, “Appraisal Report as of December 31, 2011 on Certain Properties owned by Denbury Resources Inc. SEC Case”, and “Appraisal Report as of December 31, 2010 on Certain Properties owned by Denbury Resources Inc. SEC Case”, in the Annual Report on Form 10-K of Denbury Resources Inc. for the year ended December 31, 2012.

Very truly yours,

/s/ DeGolyer and MacNaughton

DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716

Exhibit 31(a)

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

I, Phil Rykhoek, certify that:

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

/s/ Phil Rykhoek February 28, 2013

Phil Rykhoek
President and Chief Executive Officer

Exhibit 31(b)

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

I, Mark C. Allen, certify that:

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

s/ Mark C. Allen February 28, 2013

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

Exhibit 32

CERTIFICATION OF CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER

PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report on Form 10-K for the year ended December 31, 2012 (the Report) of Denbury Resources Inc. (Denbury) as filed with the Securities and Exchange Commission, each of the undersigned, in his capacity as an officer of Denbury, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

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

/s/ Phil Rykhoek February 28, 2013

Phil Rykhoek
President and Chief Executive Officer

/s/ Mark C. Allen February 28, 2013

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

CORPORATE INFORMATION

Stock Exchange Listing

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

Corporate Headquarters

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

Stock Transfer Agent & Registrar

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

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

Investor Inquiries

Phil Rykhoek
President & Chief Executive Officer
972.673.2000

Mark Allen
Senior Vice President &
Chief Financial Officer
972.673.2000

Jack Collins
Executive Director, Investor Relations
972.673.2028
Email: jack.collins@denbury.com

Annual Certifications

During 2012, our Chief Financial Officer certified to the NYSE that he is not aware of any violation by the Company of the NYSE's corporate governance listing standards.

Financial Information Requests

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

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

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

Annual Meeting

The Annual Meeting of Stockholders will be held on Wednesday, May 22, 2013, at 3:00 P.M. CDT at The Westin Stonebriar Hotel, 1549 Legacy Drive, Frisco, Texas 75034. A proxy statement and notice of the Annual Meeting has been sent to shareholders of record as of March 28, 2013.

Legal Counsel

Baker & Hostetler LLP

Bankers

J.P. Morgan (Agent)

Auditors

PricewaterhouseCoopers LLP

Reserve Engineers

DeGolyer and MacNaughton

Designed by Eisenberg And Associates

Denbury Resources Inc.

5320 Legacy Drive | Plano, Texas 75024 | 972.673.2000 | www.denbury.com