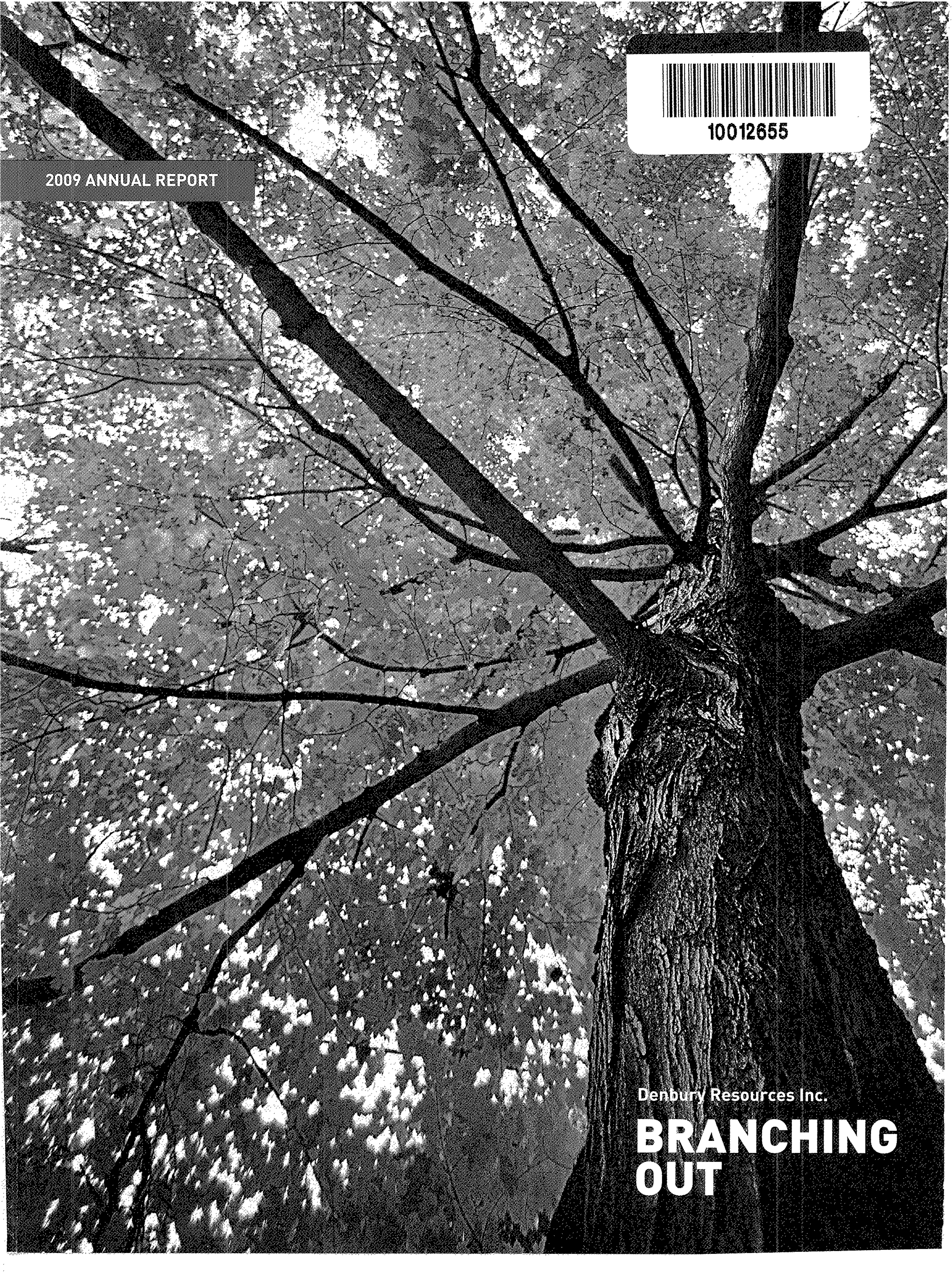
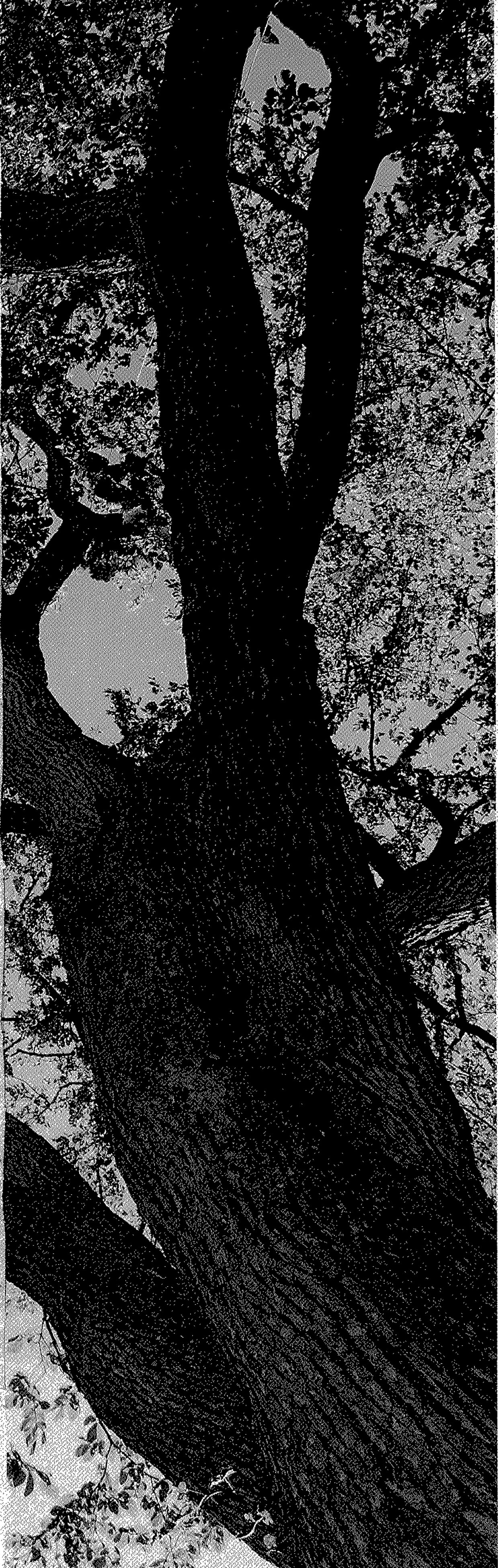


2009 ANNUAL REPORT

Denbury Resources Inc.

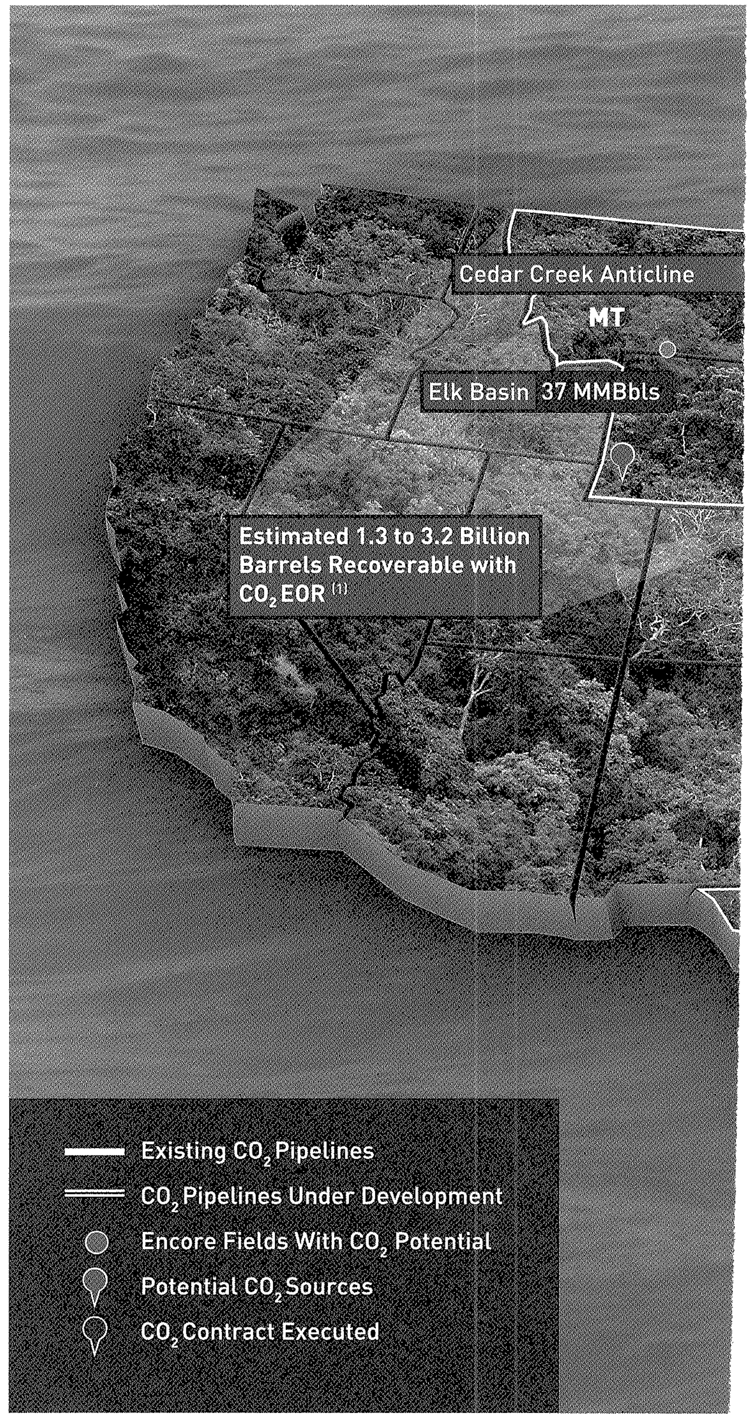
BRANCHING OUT



Branching Out

We have continued to expand our carbon dioxide (CO_2) enhanced oil recovery (EOR) operations in the Gulf Coast region and are also expanding our CO_2 EOR expertise into a new core operating area in the Rocky Mountain region.

During 2009, we made three strategic acquisitions that we believe will transform our future. We purchased two large oil fields in our Gulf Coast region, which have significant future CO_2 EOR potential, Hastings and Conroe Fields, and also purchased Encore Acquisition Company.



[1] Department of Energy 2005 and 2006 reports.

[2] Proved, probable and possible total net reserves as of December 31, 2009, based on a variety of recovery factors.

Financial Highlights

In thousands, unless otherwise noted	2009	2008	2007	2006[2]	2005	Average Annual Growth[1]
Consolidated Statements of Operations Data:						
Revenues	$ 882,493	$ 1,365,702	$ 973,060	$ 731,536	$ 560,392	12%
Net income (loss)[3]	(75,156)	388,396	253,147	202,457	166,471	-
Net income (loss) per common share[4]:						
Basic	(0.30)	1.59	1.05	0.87	0.74	-
Diluted	(0.30)	1.54	1.00	0.82	0.70	-
Weighted average number of common shares outstanding[4]:						
Basic	246,917	243,935	240,065	233,101	223,485	3%
Diluted	246,917	252,530	252,101	247,547	239,267	1%
Consolidated Statements of Cash Flow Data:						
Cash provided by (used by):						
Operating activities	$ 530,599	$ 774,519	$ 570,214	$ 461,810	$ 360,960	10%
Investing activities[5]	(969,714)	(994,659)	(762,513)	(856,627)	(383,687)	26%
Financing activities[6]	442,637	177,102	198,533	283,601	154,777	30%
Production (daily):						
Oil (Bbls)	36,951	31,436	27,925	22,936	20,013	17%
Natural gas (Mcf)	68,086	89,442	97,141	83,075	58,696	4%
BOE (6:1)	48,299	46,343	44,115	36,782	29,795	13%
Unit Sales Price (excluding hedges):						
Oil (per Bbl)	$ 57.75	$ 92.73	$ 69.80	$ 59.87	$ 50.30	4%
Natural gas (per Mcf)	3.54	8.56	6.81	7.10	8.48	(20%)
Unit Sales Price (including hedges):						
Oil (per Bbl)	$ 68.63	$ 90.04	$ 68.84	$ 59.23	$ 50.30	8%
Natural gas (per Mcf)	3.54	7.74	7.66	7.10	7.70	(18%)
Costs per BOE:						
Lease operating expenses	$ 18.50	$ 18.13	$ 14.34	$ 12.46	$ 9.98	17%
Production taxes and marketing expenses	2.41	3.76	3.05	2.71	2.54	(1%)
General and administrative[7]	6.59	3.56	3.04	3.20	2.62	26%
Depletion, depreciation and amortization	13.52	13.08	12.17	11.11	9.09	10%
Proved Reserves:						
Oil (MBbls)	192,879	179,126	134,978	126,185	106,173	16%
Natural gas (MMcf)[8]	87,975	427,955	358,608	288,826	278,367	(25%)
MBOE (6:1)	207,542	250,452	194,746	174,322	152,568	8%
Carbon dioxide (MMcf)[9]	6,302,836	5,612,167	5,641,054	5,525,948	4,645,702	8%
Consolidated Balance Sheet Data:						
Total assets	$ 4,269,978	$ 3,589,674	$ 2,771,077	$ 2,139,837	$ 1,505,069	30%
Total long-term liabilities	1,903,951	1,363,539	1,102,066	833,380	617,343	33%
Stockholders' equity[10]	1,972,237	1,840,068	1,404,378	1,106,059	733,662	28%

Year Ended December 31 (columns 2009–2005).

[1] Four-year compounded average annual growth rate computed using 2005 as a base year.

[2] Effective January 1, 2006, Denbury adopted new guidance issued by the Financial Accounting Standards Board ("FASB") in the "Compensation-Stock Compensation" topic of the FASB Accounting Standards Codification™ ("FASC") which prospectively required Denbury to record compensation expense for stock incentive awards.

[3] In 2008, we had a full cost ceiling test write-down of $226 million ($140.1 million net of tax) and pretax expense of $30.6 million associated with a canceled acquisition. These charges were partially offset by pretax income of $200.1 million on our commodity derivative contracts. In 2009, we had a pretax charge of $236.2 million associated with our commodity derivative contracts.

[4] On December 5, 2007, and October 31, 2005, we split our common stock on a 2-for-1 basis. Information relating to all prior years' shares and earnings per share has been retroactively restated to reflect the stock splits.

[5] During February 2009, we closed our $201 million purchase of Hastings Field, and in December 2009, we closed our $430.7 million purchase of Conroe Field (for $269.8 million in cash and the issuance of 11,620,000 shares of common stock). We sold our Barnett Shale natural gas assets in 2009.

[6] In February 2009, we issued $420 million of 9.75% Senior Subordinated notes due 2016.

[7] In June 2009, we recorded $10.0 million of expense related to a Founder's Retirement Agreement. During 2009, we recorded $14.2 million related to incentive compensation awards for the management of Genesis. During the fourth quarter of 2009, we recorded $8.7 million in acquisition-related expenses in conjunction the Encore Merger Agreement.

[8] In December 2007 and February 2008, we sold our Louisiana natural gas assets, and during 2009 we sold our Barnett Shale natural gas assets.

[9] Based on a gross working interests basis and includes reserves dedicated to volumetric production payments of 127.1 Bcf at December 31, 2009, 153.8 Bcf at December 31, 2008, 182.3 Bcf at December 31, 2007, 210.5 Bcf at December 31, 2006, and 237.1 Bcf at December 31, 2005. (See Note 16 to the Consolidated Financial Statements).

[10] We have never paid any dividends on our common stock.

Reporting Format: Unless otherwise noted, the disclosures in this report have (i) production volumes expressed on a net revenue interest basis, and (ii) gas volumes converted to equivalent barrels at 6:1.

See table of contents page regarding cautionary notes about forward-looking statements and unproved reserves referenced herein.

Dear Shareholders:

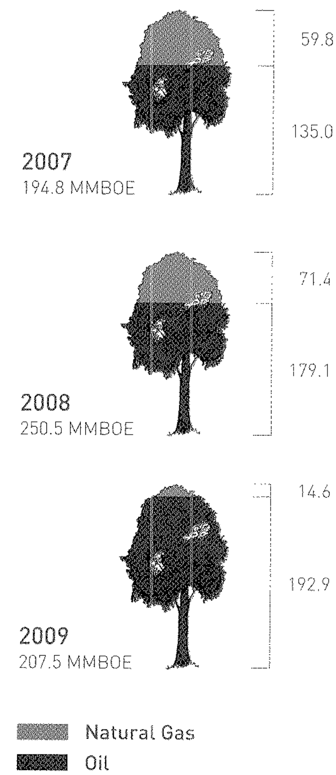
Denbury had an exciting year in 2009. We weathered the economic storms of the last 12 to 18 months without incident, thanks to our strong balance sheet, and seized the opportunity to branch out by making three strategic acquisitions, which we believe will transform our future. During the year, we bought two large oil fields in our Gulf Coast region, which have significant future enhanced oil recovery ("EOR") potential, Hastings and Conroe Fields, either of which by itself would have made 2009 a success. We went beyond the Gulf Coast and branched out into a new core operating area with the purchase of Encore Acquisition Company, expanding our CO_2 EOR expertise to the Rocky Mountains. This acquisition, at the time of the agreement, nearly doubled our inventory of potential oil reserves recoverable with CO_2 EOR, making us one of the largest oil-focused independents in North America.

Let me briefly review our history before we discuss 2009 and beyond.

Our Roots

Denbury was originally founded in 1990 as an "acquire and exploit" oil and natural gas company that also included a sizeable oil and gas exploration effort. During the late 1990's, the idea of enhanced oil recovery with CO_2 was discussed, but as we had no experience in implementing or operating a CO_2 EOR project, we were uncertain how to begin. In 1999, an opportunity arose to acquire an existing CO_2 EOR flood, Little Creek Field, at a cost of approximately $12 million. This was a relatively low-risk project and we knew it would allow us an opportunity to gain valuable CO_2 EOR experience. The purchase of Little Creek Field started us on the path to becoming one of the premier CO_2 EOR companies in the country. We subsequently purchased the CO_2 reserves at Jackson Dome, the CO_2 pipeline that serviced Little Creek

Proved Reserves
MMBOE



and several additional fields in what we now call Phase 1. We have continued to expand and grow and we now have nine identified phases. Based on the success of Little Creek and subsequent floods, our management team concluded that CO_2 EOR would be our primary focus, our core business and our niche in the oil and gas industry. As such, over the last few years we have sold most of our natural gas assets, choosing to focus on our most profitable line of business, CO_2 enhanced oil recovery.

Solid Base

We have developed and expanded our initial CO_2 EOR initiative at Little Creek Field into a solid, profitable CO_2 EOR operating company. Today we have:

- 14 fields currently being flooded with CO_2;
- nearly 835 miles of pipelines dedicated to CO_2 usage in the Gulf Coast region (once the Green Pipeline is completed in 2010);
- 26,307 Bbls/d of current (fourth quarter 2009) oil production from our CO_2 EOR operations;
- 6.3 Tcf of proven CO_2 reserves at Jackson Dome, with several more Tcf of potential;
- CO_2 purchase contracts with eight possible carbon gasification plants and letters of intent and ongoing discussions with several more;
- an experienced senior management team, three of whom have worked together for more than 10 years, supported by over 800 dedicated employees, as evidenced by our low employee turnover ratio;
- 11 years of growing CO_2 EOR experience;
- an enviable oily asset base that currently has a significantly higher gross profit than natural gas (93% of our December 31, 2009, proved reserves are oil); and
- a profitable business strategy as our estimated per barrel break-even cost on our CO_2 EOR operations, before corporate overhead, interest and taxes, is in the mid $30's, giving us a strong gross profit at today's oil prices.

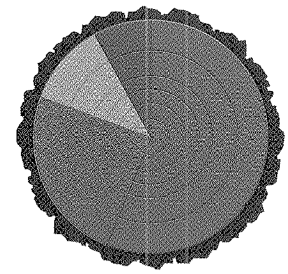
New Growth and Expansion

In our CO_2 EOR program, we have increased production from the approximately 1,300 Bbls/d we initially acquired at Little Creek to over 26,000 Bbls/d in the fourth quarter of 2009. For the year, our tertiary production averaged 24,343 Bbls/d, a 26% increase over our 2008 tertiary oil production. Our current tertiary oil production is made possible by the significant source of CO_2 that we own at Jackson Dome near Jackson, Mississippi. We acquired our initial Jackson Dome assets in 2001 for $42 million and have developed and expanded this vital resource from the 0.8 Tcf of proven CO_2 reserves at the time it was acquired to 6.3 Tcf of proven CO_2 reserves today, with significant additional remaining potential.

As of the beginning of 2009, we had approximately 160 MMBbls of total CO_2 EOR potential in our inventory. Early in the year, we purchased Hastings Field, the anchor field for our Green Pipeline, which has between 60 and 90 MMBbls of potential CO_2 recoverable oil. We further expanded our Gulf Coast operations with the purchase of Conroe Field late in 2009, adding another 130 MMBbls of potential. By year-end 2009, our potential recoverable oil with CO_2 EOR in the Gulf Coast area totaled approximately 368 MMBbls, a significant quantity, but still only a fraction of what the Department of Energy estimates can be recovered with CO_2 in the Gulf Coast. Our growth in this region has been strong, and the Gulf Coast properties in our existing inventory are expected to provide 10% to 20% production growth for many years, with significant additional potential that can be acquired.

Late in 2009, we agreed to acquire Encore Acquisition Company, closing the transaction on March 9, 2010. We were attracted to Encore primarily because of its large legacy oil fields in the Rockies that we believe are amenable to CO_2 EOR, which at the time we executed the merger

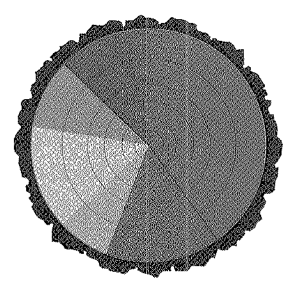
Projected 2010 Capital Budget - Denbury Only[1]
$650 Million



in millions

- Tertiary Floods $365
- CO_2 Pipelines $159
- Jackson Dome CO_2 $74
- Other $52

Projected 2010 Capital Budget - Combined[1]
$1.0 Billion



in millions

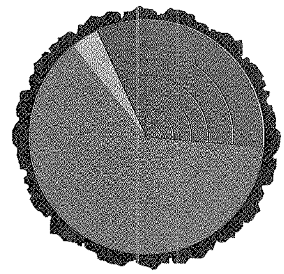
- Tertiary Floods $400
- CO_2 Pipelines $159
- Jackson Dome CO_2 $74
- Bakken $142
- Haynesville $99
- Other $126

[1] Excludes potential acquisitions and capitalized interest. Net of $50 million of assumed lease financing.

agreement, nearly doubled our total CO_2 EOR upside. We view this acquisition as an opportunity to leverage our CO_2 EOR expertise by expanding to another region of the United States, giving us immediate reserve and production growth and another core area with numerous potential growth and expansion opportunities. We believe that our CO_2 EOR experience, coupled with our willingness to make significant commitments of infrastructure capital and desire to enter into long-term CO_2 purchase contracts, gives us an advantage over our peers in extracting EOR value from these old oil fields. We have demonstrated that CO_2 EOR provides a competitive rate of return, has minimal geological risk as compared to other industry activities and continues to be the most efficient and profitable tertiary recovery method, assuming there are significant sources of available CO_2. Encore has contracted for one source of CO_2 in their operating area, and it is our goal to significantly expand our sources of CO_2 in that region in the near future. We expect to further define and delineate our CO_2 options in this region during 2010.

In addition to their CO_2 EOR assets, Encore possessed a significant acreage position in the Bakken play in North Dakota (approximately 300,000 net acres), which should provide us with near-term production growth until our CO_2 EOR operations and production commence. We like this play because it is oily with attractive rates of return at current prices. Encore's remaining assets, in their Southern region, included properties in the Permian Basin, Mid-Continent and East Texas areas and approximately 19,000 net acres in the Haynesville play. We plan to sell a portion of these assets in order to reduce our leverage incurred as part of the acquisition and to concentrate our focus on assets that are core to Denbury's strategy. We expect to sell between $500 million and $1.0 billion worth of these assets, with the

2009 Capital Expenditures[1]
$865 Million



in millions
- Tertiary Floods $229
- CO_2 Pipelines $543
- Jackson Dome CO_2 $33
- Other $60

[1] Excludes acquisitions and capitalized interest.

final amount and identity of assets likely dependent on offers received, which in turn are highly dependent on commodity prices. We anticipate starting the sale process in the near future, and if things proceed as planned, we will have some of these asset sales closed by the end of the second quarter.

With the Encore transaction, we have more than one billion barrels of potential recoverable oil in our inventory, which we believe will provide us almost a decade of production growth. Further, although this inventory of potential CO_2 EOR floods is significant, we own only a fraction of the total EOR potential in our two primary operating regions. We have a lot of work to do to develop this potential, but we are extremely pleased with the way the Company is currently positioned to exploit our premier CO_2 EOR franchise. 2010 will be a year of transition as we work diligently to integrate the Encore assets and personnel, sell a portion of our acquired Encore assets to reduce acquisition debt and further define our development plans. We clearly understand our strategy, we know what our mission is and we appreciate your support as we continue to create shareholder value.

Phil Rykhoek

Phil Rykhoek
Chief Executive Officer

March 10, 2010

With the Encore transaction, we have more than one billion barrels of potential recoverable oil in our inventory, which we believe will provide us with almost a decade of production growth.

Encore

Encore Acquisition

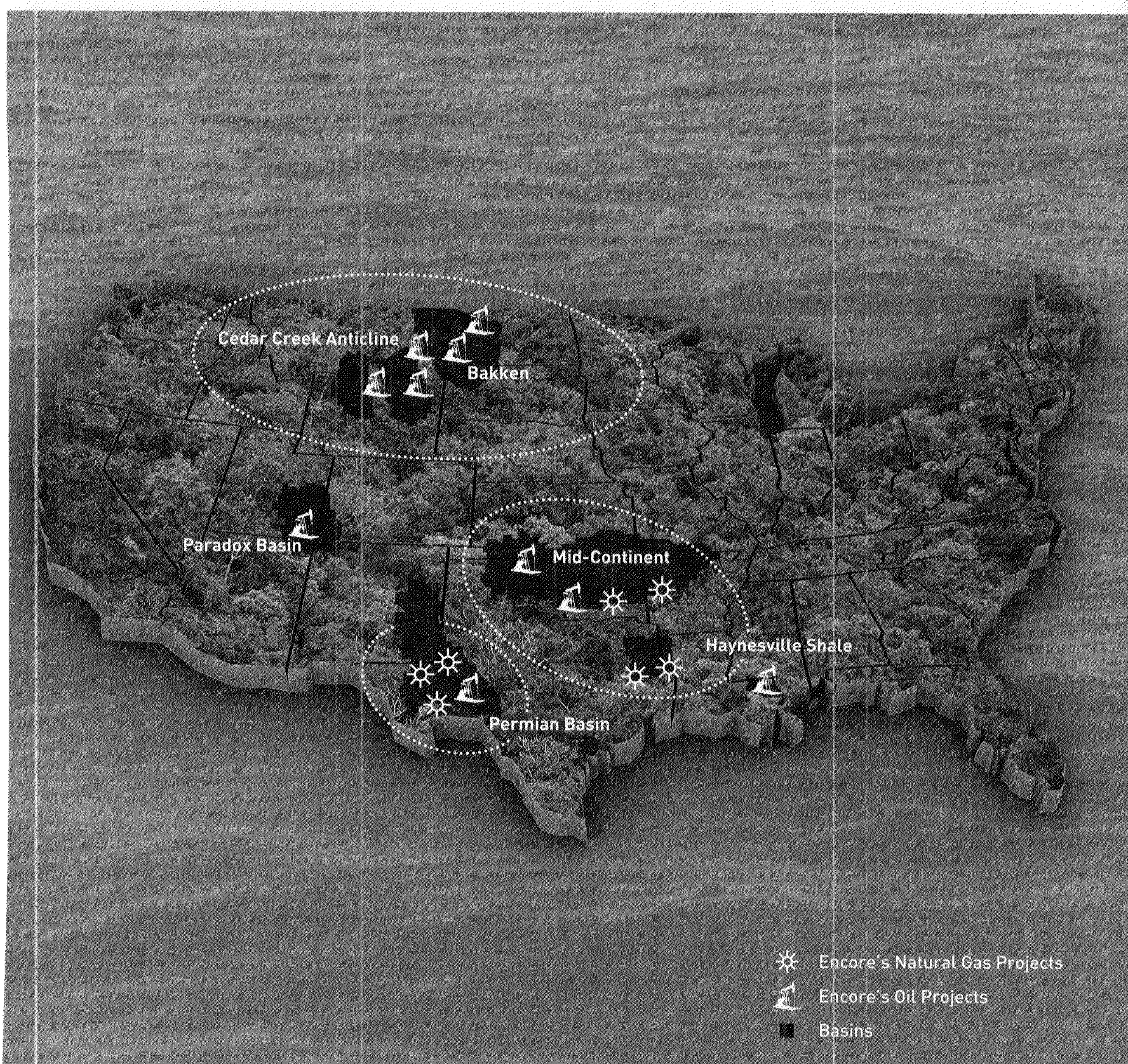
Our initial and primary interest in acquiring Encore Acquisition Company (Encore) was to obtain the large legacy oil fields they owned in Wyoming, Montana and North Dakota that we believe are amenable to CO_2 EOR operations. These legacy oil fields have over six billion barrels of original oil in place. At the time of our announcement, Encore's CO_2 EOR potential from these fields essentially doubled our existing CO_2 EOR potential. In addition to their CO_2 EOR potential, Encore owned approximately 300,000 net acres in the Bakken oil shale play in North Dakota, 19,000 net acres in the Haynesville shale play in Louisiana and additional assets throughout the U.S. Mid-Continent region, Permian Basin and East Texas. Encore was the general partner and also owned approximately 47% of Encore Energy Partners (NYSE: ENP), an oil and gas master limited partnership.

CO_2 EOR Potential

The three significant oil fields with CO_2 EOR potential are Bell Creek in Montana, Cedar Creek Anticline in North Dakota and Montana and Elk Basin in Wyoming (currently owned by ENP). The CO_2 EOR potential in these three fields essentially doubled our existing CO_2 EOR potential. Encore secured one source of CO_2 from an existing natural gas plant in Wyoming, and prior to our announcement, were finalizing plans to construct a CO_2 pipeline that would deliver this CO_2 to Bell Creek. We elected to delay their pipeline project for up to a year in order to develop a more comprehensive plan, give us time to contract additional CO_2 supplies and likely expand the size and scope of the pipeline project.

Bell Creek is a 30 MMBbl oil field that produces from a sandstone reservoir at less than 5,000 feet and is similar to many of Denbury's existing CO_2 floods in the Gulf

Encore owned approximately 300,000 net acres in the Bakken oil shale play in North Dakota, 19,000 net acres in the Haynesville shale play in Louisiana and additional assets throughout the U.S. Mid-Continent region, Permian Basin and East Texas.


Cedar Creek Anticline
Bakken
Paradox Basin
Mid-Continent
Haynesville Shale
Permian Basin
Encore's Natural Gas Projects
Encore's Oil Projects
Basins

Coast. Bell Creek was originally unitized by Exxon with the intent to ultimately CO_2 flood the field. Due to low oil prices in the 1980's, many of the wells in Bell Creek were "pickled" and temporarily abandoned for future CO_2 EOR utilization. Encore began reactivating many of the "pickled" wells in 2008 with no failures. In addition to the reactivation program, Encore began injecting water into the field in order to raise the reservoir pressure in anticipation of the arrival of CO_2. Upon completion of the planned CO_2 pipeline system, CO_2 EOR operations will be initiated at Bell Creek.

The Cedar Creek Anticline covers a very large area in North Dakota and Montana. The Anticline is a series of oil units that produces from numerous carbonate oil reservoirs. Initial development of the Anticline was conducted by Shell Oil Company, which included primary production and ultimately water flood operations. In the 1980's, Shell was evaluating CO_2 EOR operations in many places throughout the United States and initiated CO_2 EOR operations in West Texas, Mississippi, Louisiana and Montana. They conducted a pilot project at the Anticline in the South Pine Unit. The pilot project demonstrated that CO_2 EOR operations would recover approximately 18% of the original oil in place, very similar to our expected recoveries in the Gulf Coast. Using a 16% recovery factor, we estimate that nearly 200 MMBbls of potential oil could be recovered from the Anticline from CO_2 EOR operations. We are developing plans for the pipeline, field development and CO_2 sources and hope to initiate CO_2 EOR operations here in three to five years.

Elk Basin is a 37 MMBbl oil field located in northwestern Wyoming. Elk Basin is another very large field that produces from multiple carbonate reservoirs. Reservoirs within the field have been successfully water flooded and there is currently a flue gas injection project ongoing in one reservoir. Based on dimensionless modeling, CO_2 operations at Elk Basin look promising.

Unconventional Plays

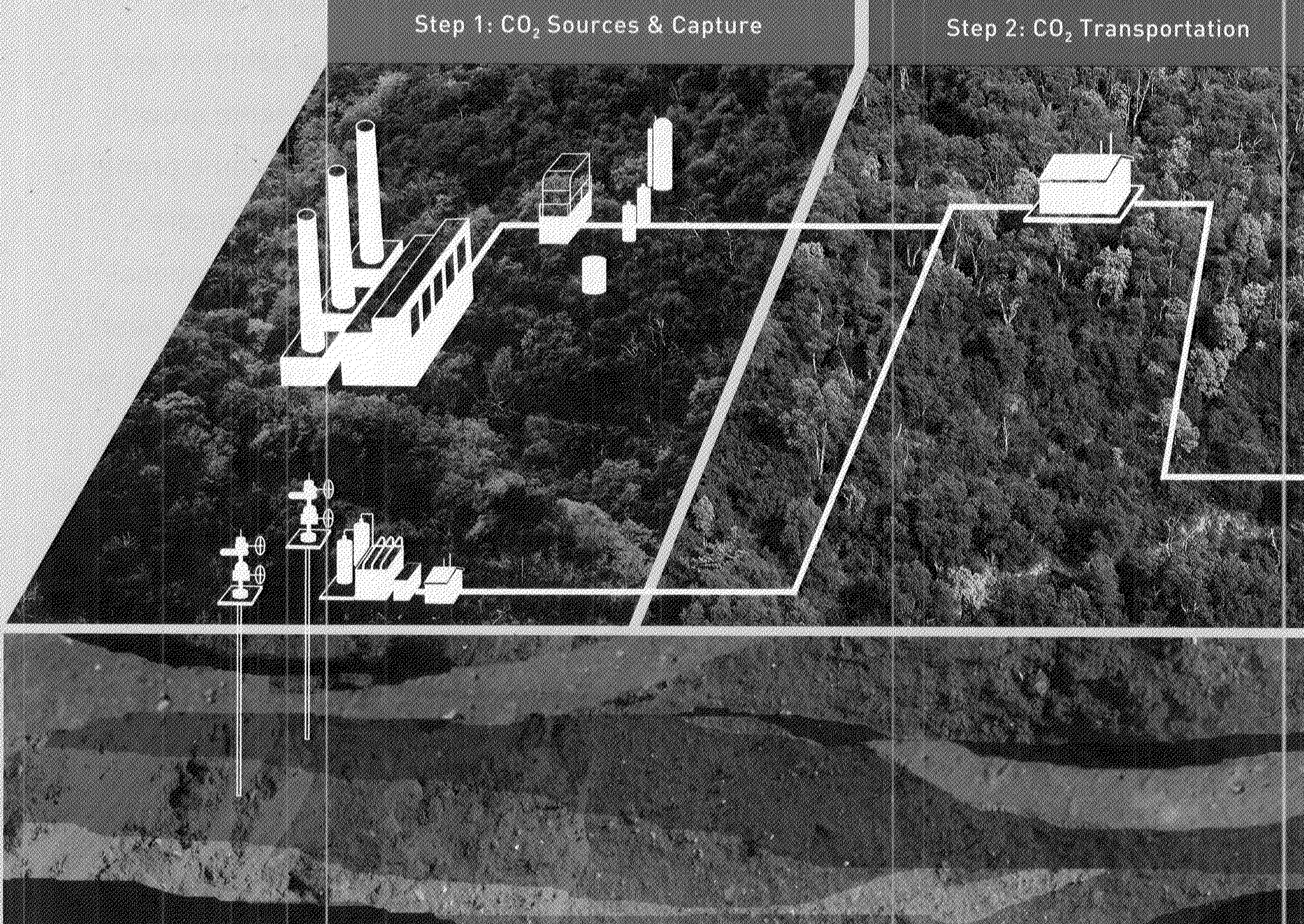
Near-term production and reserve growth will come primarily from Encore's unconventional plays. With nearly 300,000 net acres under lease in the Bakken oil play in North Dakota, Encore possessed a top ten acreage position. The Bakken oil play has been developed over the past several years by many operators and has grown into arguably the leading oil play within North America. Although we don't anticipate any significant CO_2 EOR potential from the Bakken Shale, it can provide near-term oil production and reserve growth while we develop our CO_2 EOR operations. Although Encore had a much smaller acreage position within the Haynesville play in Louisiana, approximately 19,000 net acres, much of the acreage is located within the core area of the play. The Haynesville Shale produces primarily natural gas and thus, combined with a smaller acreage position and corresponding smaller reserve potential, we may divest or trade our acquired position in the Haynesville.

Other Assets

Encore owned additional assets throughout many states including Arkansas, Kansas, Louisiana, New Mexico, Oklahoma, Texas and Utah. With little or no CO_2 EOR potential within these assets and limited conventional development opportunities, the vast majority of these assets will be divested or traded. Although these assets do not fit within our strategy or portfolio, we believe these assets will be very attractive to companies that are actively operating and developing properties in these areas. We have received numerous inquiries concerning these properties and are in the process of preparing the necessary data and information to begin marketing these properties.

Near-term production and reserve growth will come primarily from Encore's unconventional plays. With nearly 300,000 net acres under lease in the Bakken oil play in North Dakota, Encore possessed a top ten acreage position.

Our CO_2 cycle consists of the four steps illustrated below. Denbury captures carbon dioxide and transports it to mature oil fields to increase production and create numerous economic and social benefits.

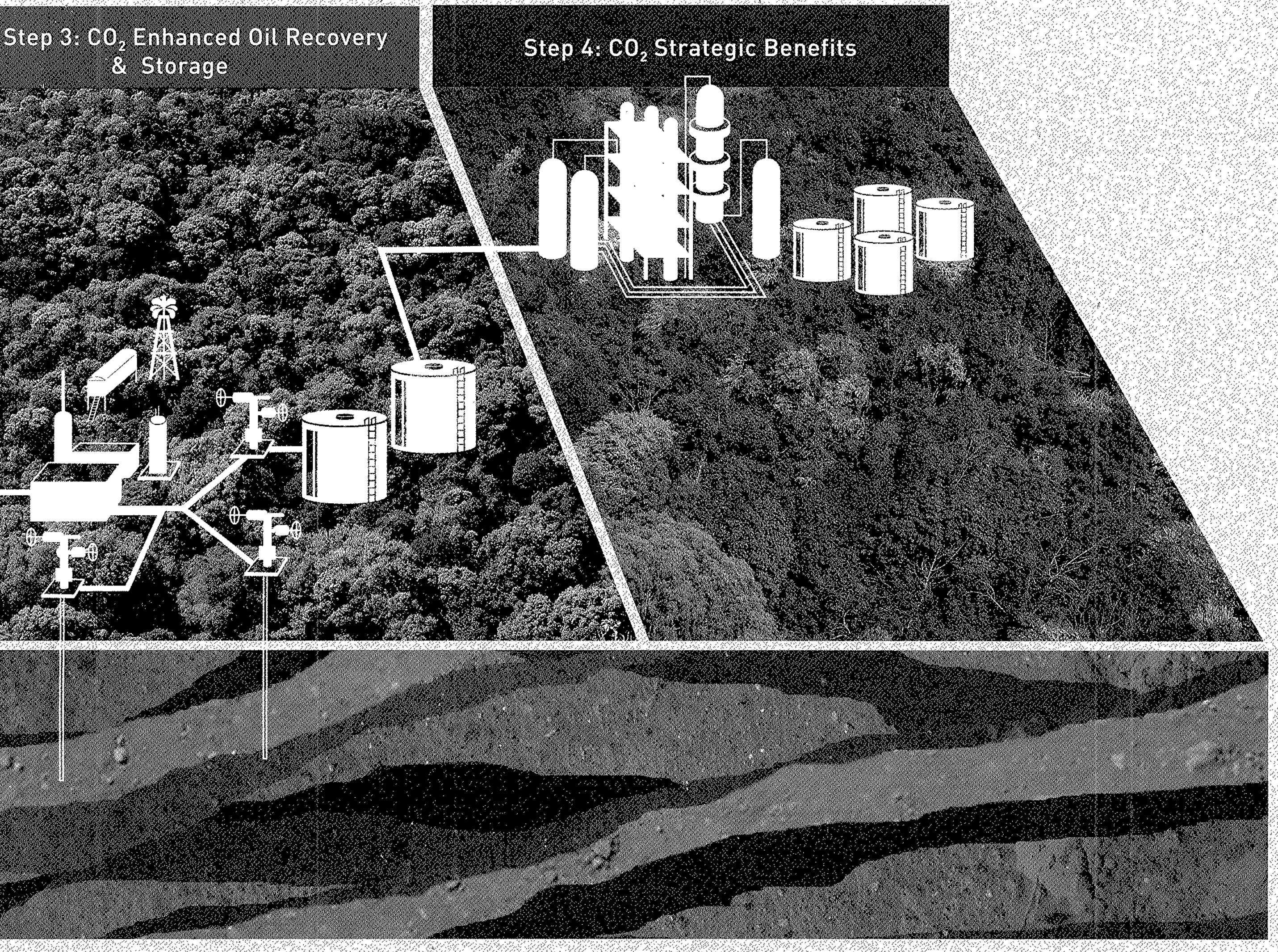


Step 1:
CO_2 Sources & Capture

Denbury has its own natural source of CO_2 at Jackson Dome in Mississippi and intends to capture anthropogenic (man-made) volumes from power plants or industrial sources. CO_2 capture occurs when natural or anthropogenic CO_2 is purified and dried for transportation to oil fields.

Step 2:
CO_2 Transportation

Denbury currently operates or controls over 515 miles of CO_2 pipelines, which distribute CO_2 from Jackson Dome to our oil fields. We are currently completing construction of the 320-mile Green Pipeline to Texas, which will allow us to potentially transport anthropogenic volumes of CO_2 from the Gulf Coast region to our CO_2 EOR fields.

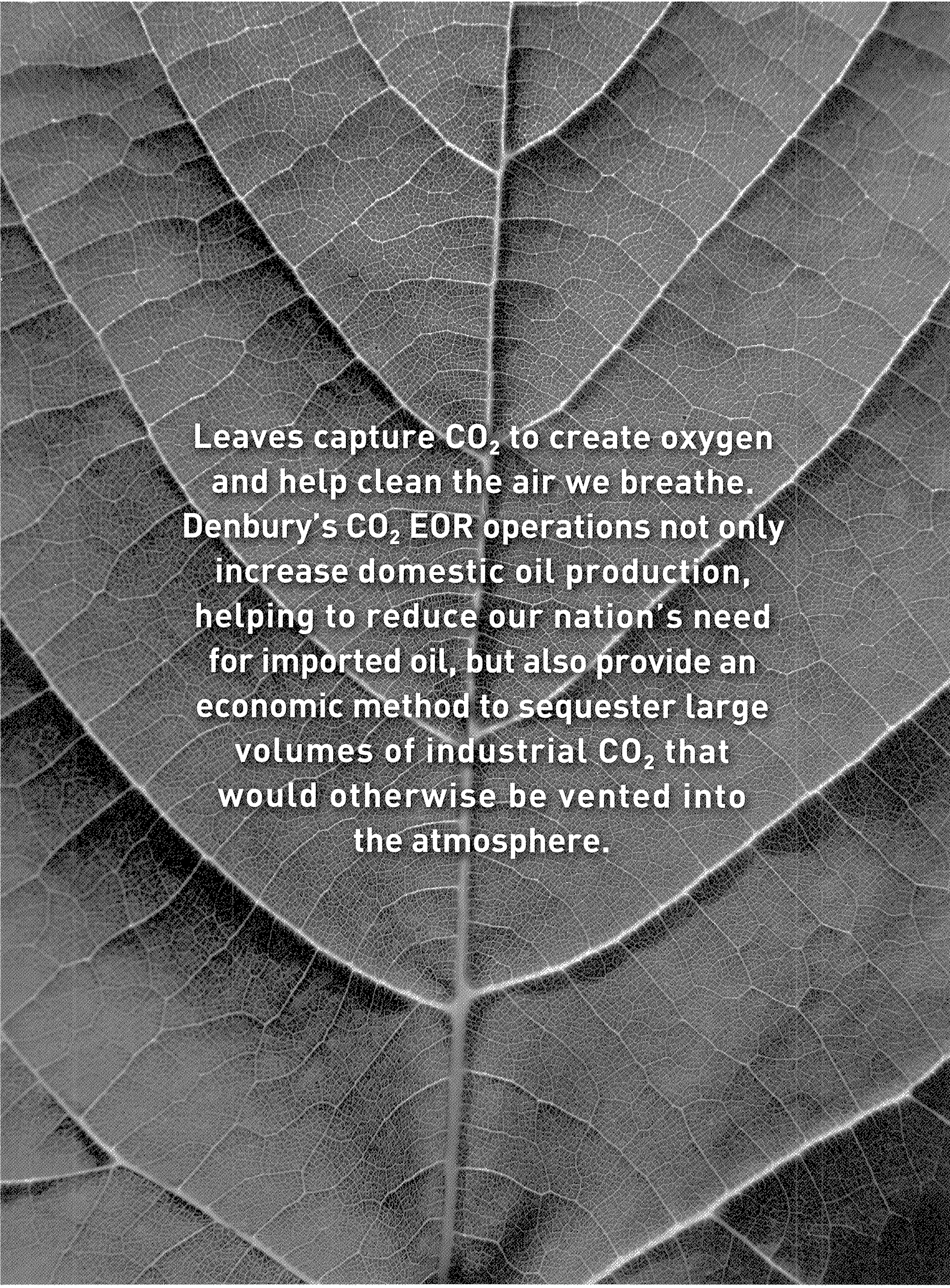


Step 3:
CO_2 Enhanced Oil Recovery & Storage

Our CO_2 enhanced oil recovery (CO_2 EOR) operations have demonstrated the ability to recover significant amounts of additional oil, and also have provided a promising method to sequester anthropogenic volumes of CO_2 in depleted oil reservoirs.

Step 4:
CO_2 Strategic Benefits

After the CO_2 EOR process is completed, the CO_2 is left sequestered in the geological formation that trapped the oil originally. Oil production in these domestic fields enriches the local economy, royalty owners and Denbury shareholders while reducing the need for imported oil.



Leaves capture CO_2 to create oxygen and help clean the air we breathe. Denbury's CO_2 EOR operations not only increase domestic oil production, helping to reduce our nation's need for imported oil, but also provide an economic method to sequester large volumes of industrial CO_2 that would otherwise be vented into the atmosphere.

1 CO_2 Sources & Capture

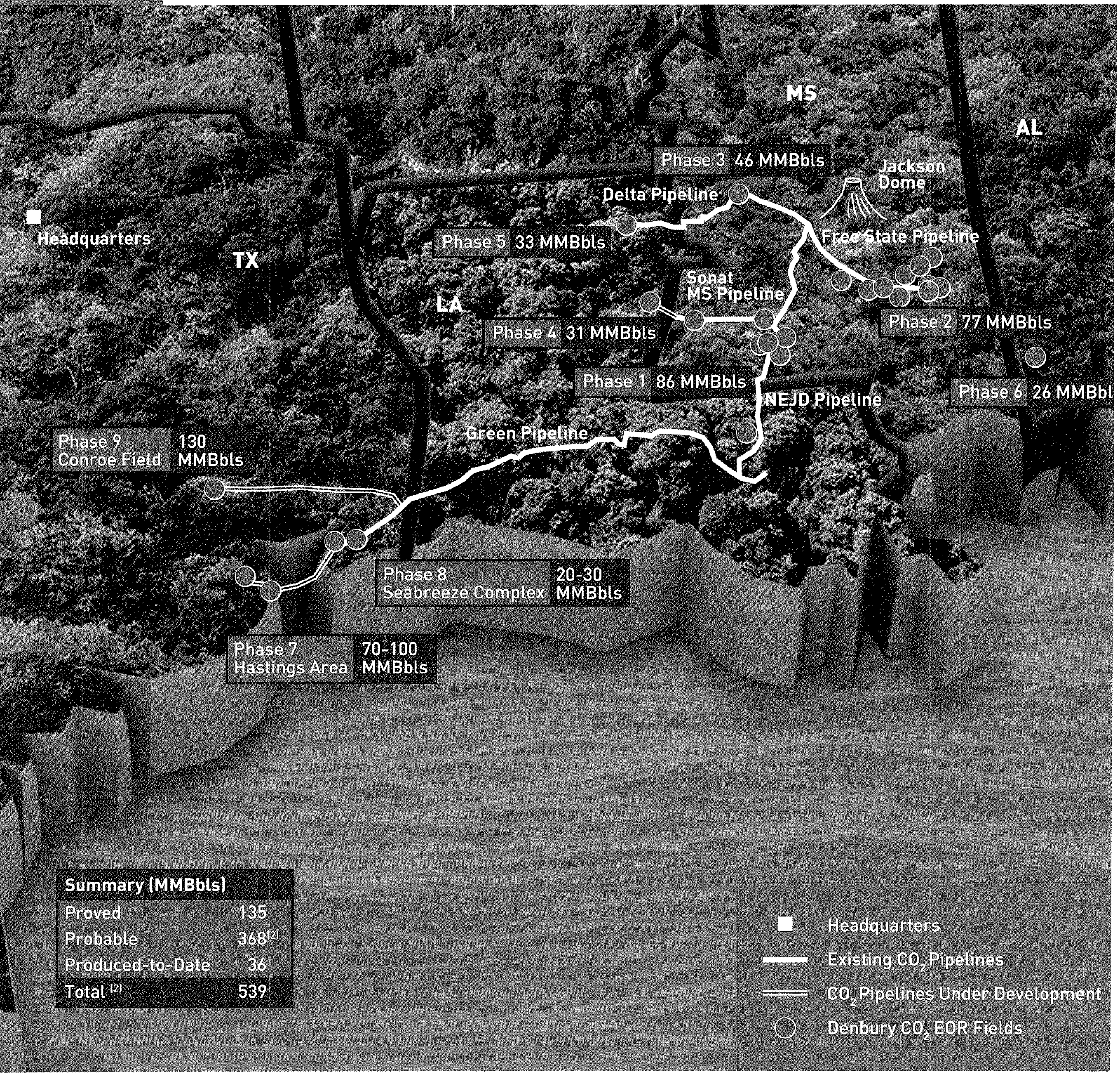
Natural CO_2 Source

Denbury currently uses carbon dioxide (CO_2) from our underground natural source at Jackson Dome located near Jackson, Mississippi. Such natural sources are rare, and to our knowledge, we have the only large natural source of CO_2 in the Gulf Coast region. We use CO_2 to extract additional amounts of oil from reservoirs in mature, depleted oil fields. This process, referred to as tertiary or CO_2 enhanced oil recovery (CO_2 EOR), requires large volumes of nearly pure CO_2. While naturally produced CO_2 drives our operations today, we plan to use anthropogenic (man-made) CO_2 from industrial sources in future tertiary operations.

The CO_2 at Jackson Dome was originally discovered by companies looking for oil and gas in the 1960's and 1970's, and was initially thought to have little commercial value. However, following the oil crisis of the 1970's, several oil companies experimented with CO_2 for enhanced oil recovery, and by the 1980's, Shell Oil Company had started a project to produce CO_2 at Jackson Dome for this purpose. Low oil prices in the ensuing years hindered this effort, and in 2001, Denbury acquired most of the assets that remained from this early effort, including producing CO_2 wells, facilities and a CO_2 pipeline. Since 2001, we have steadily expanded the production capacity at Jackson Dome, increasing production of CO_2 from 55 MMcf/d, at the time we acquired the property, to an average of 790 MMcf/d during the fourth quarter of 2009. In 2010, we expect the production capacity of our CO_2 wells to increase to over 1 Bcf/d.

Likewise, our proved reserves of CO_2 at Jackson Dome have increased from 0.8 Tcf at the time of acquisition to 6.3 Tcf as of December 31, 2009. Approximately 1 Tcf of CO_2 proved reserves were added during 2009. Based on internal estimates, we believe there are at least an additional 2 Tcf of probable CO_2 reserves at Jackson Dome, and an additional 2 Tcf of possible reserves. We currently own 30 producing wells, four dehydration facilities and many miles of gathering pipelines around Jackson Dome. We estimate that Denbury now injects more CO_2 per day (excluding recycled volumes) into its active CO_2 EOR projects than any other company in the world.

Map Total Gulf Coast Potential Tertiary Oil Reserves[1]



[1] Proved plus probable tertiary oil reserves as of 12/31/09, including past production, based on a range of recovery factors.

[2] Using mid-points of range.

1

CO_2 Sources & Capture

Anthropogenic Sources

While naturally produced CO_2 drives our operations today, we are also pursuing anthropogenic sources of CO_2 to use in future tertiary operations. In addition to helping us recover additional oil, this will provide an economical way to sequester large volumes of anthropogenic CO_2. According to the Department of Energy, CO_2 EOR has the potential to produce 39 to 48 billion barrels of American oil that are not otherwise recoverable today while storing billions of tons of CO_2.

Many industrial activities 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, which releases CO_2 as a by-product of combustion. These facilities release significant volumes of CO_2. It has been proposed by those concerned about atmospheric CO_2 levels that these emissions be reduced by some means. At this time, the only method of beneficially using CO_2 that does not ultimately re-release the CO_2 into the atmosphere would be to capture this CO_2 and utilize it in CO_2 EOR operations. Our CO_2 EOR operations provide a proven method to sequester these CO_2 volumes in oil reservoirs while increasing domestic supplies of oil at the same time.

We have entered into eight contracts with owners of potential sources of CO_2 in the Gulf Coast and Midwest regions and have signed Letters of Intent or Memoranda of Understanding ("MOU") with numerous other project owners. These contracts are possible because of our ability to utilize Jackson Dome CO_2 volumes to buffer the inherent imbalances between industrial supplies and the demands of our oil fields and because of our willingness and ability to enter into long-term take-or-pay contracts with the plant owner. These contracts are also possible because of our significant inventory of oil fields that are either currently being flooded or that we expect to flood, our extensive CO_2 pipeline infrastructure and our expertise and confidence in the CO_2 EOR process. Generally, the current signed contracts and MOUs are for proposed plants which would employ gasification, none of which are currently under construction.

Gasification is a process by which carbon in the form of lignite, coal, petroleum coke, biomass or mixtures of solid carbon is combined with pure oxygen, producing primarily syngas, which can then be used as a fuel source

1

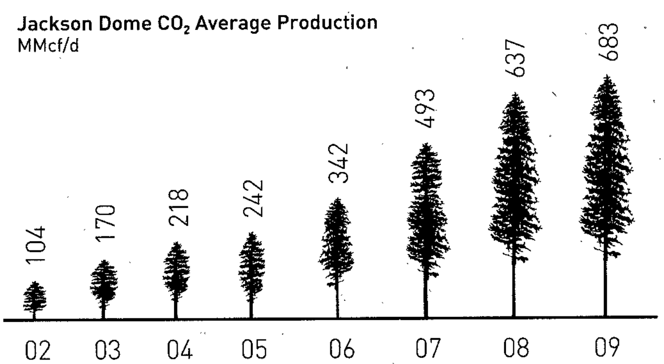
CO_2 Sources & Capture

in power plants and industrial processes as a natural gas substitute. The syngas can be converted into various chemicals, synthetic natural gas (CH_4) or utilized directly to fuel power plants. The gasification process also produces a stream of CO_2 that can be easily concentrated and delivered into a pipeline system and sequestered as part of our CO_2 EOR operations. These gasification plants are generally referred to as pre-combustion capture projects.

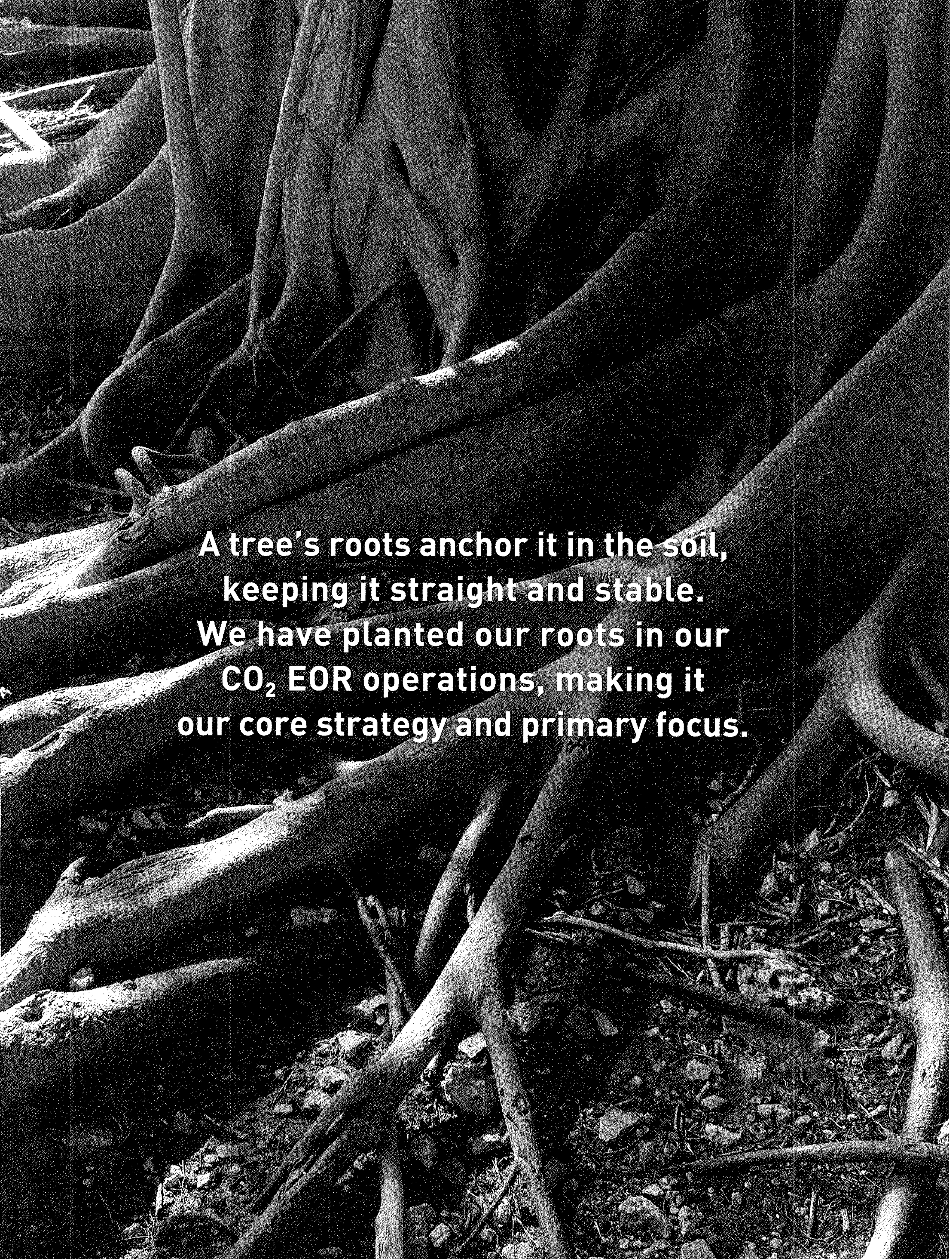
Existing emitters of CO_2, such as conventional power plants, are considering capturing CO_2 emissions after combustion (post-combustion capture). We are in discussions with several potential post-combustion capture projects, but no firm contracts have been executed at this time. We believe that due to the significant cost to capture CO_2 from conventional plants, some incentive, legislative or economic, will be necessary before this becomes a common practice.

It is possible that legislation targeting CO_2 emissions could be forthcoming. If it occurs, we believe this could increase the quantities of CO_2 available to us, allowing us to grow and expand our CO_2 EOR operations to additional oil fields.

Jackson Dome CO_2 Average Production
MMcf/d



While naturally produced CO_2 drives our operations today, we are also pursuing anthropogenic sources of CO_2 to use in future tertiary operations.


A tree's roots anchor it in the soil,
keeping it straight and stable.
We have planted our roots in our
CO_2 EOR operations, making it
our core strategy and primary focus.

2 CO_2 Transportation

CO_2 pipelines have been operating in the United States for over 30 years and have a remarkable safety record. Although there have been unplanned releases of CO_2 due to third-party damage to pipelines, there have been no fatalities associated with CO_2 pipeline transportation. CO_2 is a non-toxic, non-explosive, non-flammable gas that humans consume in soft drinks and exhale into the environment as they breathe. The primary risk with CO_2 is that it can displace oxygen and cause suffocation if allowed to accumulate in large amounts in a confined space. However, CO_2 normally disperses into air rapidly.

Denbury is advancing its CO_2 pipeline network to reach targeted oil fields, currently operates or controls over 515 miles of CO_2 pipelines and has approximately 320 miles of pipeline under construction. These pipelines stretch from Jackson Dome to our producing regions in Mississippi, Louisiana and Texas. We are in the process of completing the Green Pipeline, which will run from the end of our NEJD Pipeline near Donaldsonville, Louisiana, south of Baton Rouge, Louisiana, westward to our Hastings Field, south of Houston, Texas. Pipeline construction has been completed to our Oyster Bayou Field, and construction across Galveston Bay to our Hastings Field will be completed late this year. This pipeline is a key element to our expansion strategy and will not only allow us to send Jackson Dome CO_2 to fields in Texas, but will also allow us to transport anthropogenic sources of CO_2 from the various emission sources and industrial facilities along its route. Potentially, these anthropogenic sources could provide volumes several times greater than the volumes of CO_2 we expect to transport from Jackson Dome. Therefore, even a small percentage of these volumes would significantly enhance our ability to initiate CO_2 EOR projects in new oil fields.

In light of our December 2009 purchase of Conroe Field in Southeast Texas, we also plan to build an approximately 80-mile CO_2 pipeline that will transport CO_2 to Conroe Field from the Green Pipeline. We are currently evaluating the pipeline route and expect to commence construction in the next two to three years.

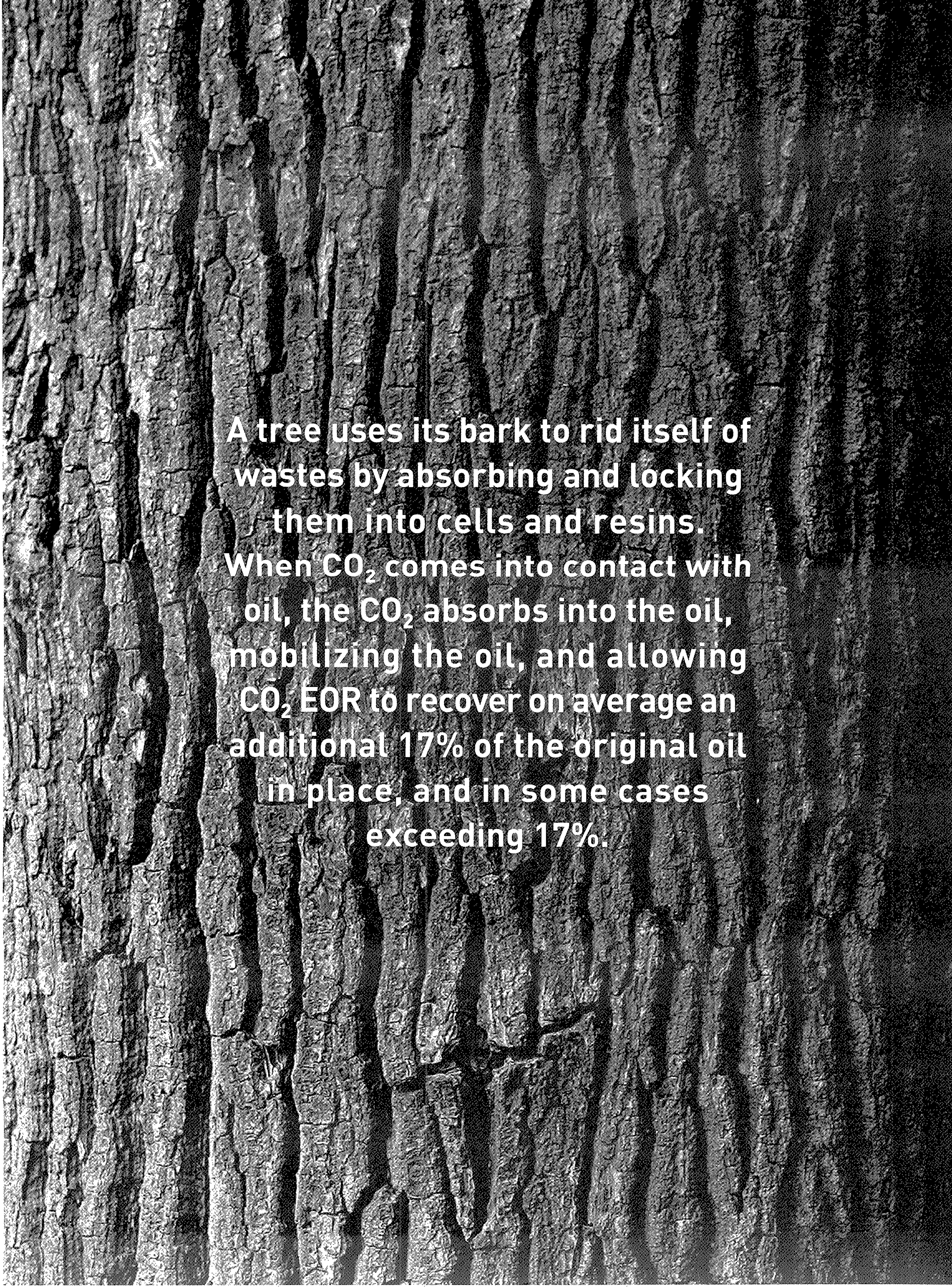
We have completed a feasibility study to build a 500- to 700-mile CO_2 pipeline from the industrial Midwest and connect it to Denbury's existing CO_2 pipeline infrastructure in the Gulf Coast. The "Midwest Pipeline," with costs preliminarily estimated at $1.0 billion or more, would allow us to expand operations and transport significant volumes of anthropogenic CO_2 to oil fields along the Gulf

Coast. This pipeline is contingent on the development of sufficient sources of CO_2 in the Midwest at reasonable economics in order to justify the capital expenditure.

With the federal government encouraging innovative coal gasification projects through federal loan guarantee and economic stimulus programs, Denbury has entered into agreements with several project developers to purchase CO_2 from proposed gasification plants in the Gulf Coast and Midwest for use in our Gulf Coast operations. Today there are no significant volumes of anthropogenic CO_2 being captured and sequestered in the Gulf Coast area. To become a reality, many factors must come together favorably, including capital cost and regulatory, legal and permitting requirements. All of our pipeline infrastructure will be connected to CO_2 being produced from Jackson Dome, which potentially allows Jackson Dome to buffer the inherent imbalances that will occur between supply and demand for CO_2. Since the CO_2 emitters need someone to reliably take their gas 24 hours a day, 365 days a year, our unique flexibility allows us to contract for anthropogenic volumes for long periods of time, as much as 15 to 20 years.

CO_2 is dehydrated before it is transported, which allows CO_2 pipelines to be constructed using relatively standard carbon steel pipe. CO_2 pipelines generally operate at pressures in excess of 2,000 psi, which allows for the CO_2 to be transported in a super critical state (the so-called dense phase), which allows for significantly higher capacities than if the CO_2 was transported as a gas.

The Green Pipeline is a key element to our expansion strategy and will not only allow us to send Jackson Dome CO_2 to fields in Texas, but will also allow us to transport anthropogenic sources of CO_2 from the various emission sources and industrial facilities along its route.


A tree uses its bark to rid itself of wastes by absorbing and locking them into cells and resins. When CO_2 comes into contact with oil, the CO_2 absorbs into the oil, mobilizing the oil, and allowing CO_2 EOR to recover on average an additional 17% of the original oil in place, and in some cases exceeding 17%.

3 CO_2 Enhanced Oil Recovery & Storage

CO_2 Enhanced Oil Recovery

Our strategy of CO_2 capture and transportation is to provide sufficient volumes to pursue the Company's ultimate goal of increasing oil production and reserves in depleted reservoirs through CO_2 enhanced oil recovery (CO_2 EOR). In most U.S. oilfields, about 33% of the original oil in place is recoverable through primary and secondary methods, increasing to 50% to 60% with CO_2 EOR.

It is estimated that the Gulf Coast region (Alabama, Mississippi, Louisiana and Southeast Texas) originally contained approximately 44.4 billion barrels of oil in place. Assuming that sufficient supplies of CO_2 are captured and delivered to the oil fields in the region, it is estimated that up to 7.5 billion barrels of oil could be recovered through CO_2 EOR projects. Denbury's ownership of the only natural CO_2 source in the area and our CO_2 pipeline system infrastructure provides us with a significant competitive advantage. We are able to acquire depleted fields in our areas of operation with significant CO_2 EOR potential, and ultimately produce the oil that would not otherwise be recoverable.

Denbury has planned the development of our oil fields over a series of nine phases, each phase representing a group of nearby fields. In some cases, the fields are large enough to be a phase by themselves (e.g., Tinsley Field, Delhi Field and Conroe Field). Typically, we acquire these fields two to five years ahead of our planned CO_2 flood, with our latest acquisition being Conroe Field (Phase 9) purchased in December 2009.

In the fourth quarter of 2009, Denbury produced an average of 26,307 Bbls/d from 13 fields in Phases 1, 2, 3 and 4. Our longest active CO_2 EOR projects are located in Phase 1 (Southwest Mississippi), where we currently

Denbury's ownership of the only natural CO_2 source in the Gulf Coast region and our CO_2 pipeline system infrastructure provides us with a significant competitive advantage.

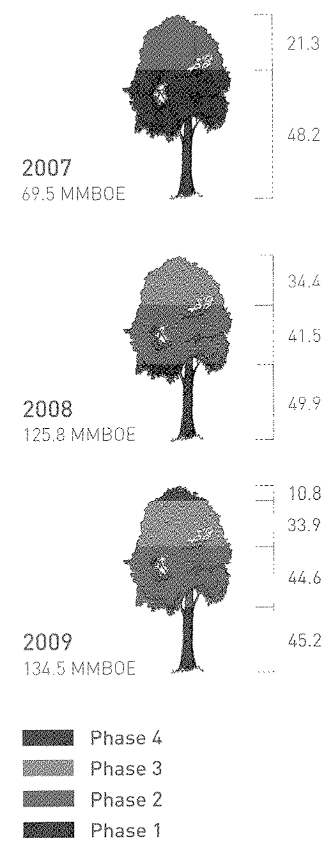
3

CO_2 Enhanced Oil Recovery & Storage

operate seven floods. Phase 2 was initiated following the construction and commissioning of the Free State Pipeline in 2006. We currently operate four producing CO_2 EOR projects within Phase 2. CO_2 EOR operations at Tinsley Field (Phase 3), currently our largest producer, were initiated in 2007 with our first oil response occurring in early 2008. Production continued to increase throughout 2009 and grew to an average daily production of 3,942 Bbls in the fourth quarter of 2009. Our Phase 4 CO_2 EOR project at Cranfield was initiated in the second half of 2008, with first oil production response during the first quarter of 2009. Production grew to an average daily production of 728 Bbls in the fourth quarter of 2009. Our Phase 5 CO_2 EOR project at Delhi Field was initiated in the second half of 2009, following the completion of the Delta Pipeline in late 2009 from Tinsley Field to Delhi Field. First production from Delhi Field is expected in the second quarter of 2010. We also plan to complete construction of the last phase of the Green Pipeline from Galveston Bay in Southeast Texas, to producing fields near Houston, Texas. The completion of the initial portion of the Green Pipeline (Donaldsonville to Galveston Bay) will allow us to initiate CO_2 EOR operations at Oyster Bayou (Phase 8) in mid 2010, with first production expected in 2011. Following the completion of the remaining portion of our Green Pipeline across Galveston Bay and on to Hastings Field, expected in late 2010, we plan to initiate CO_2 injections in Hastings Field (Phase 7) during early 2011.

In 2009, we were able to book additional CO_2 tertiary oil reserves of 17.6 MMBbls, increasing our tertiary reserves to 135 MMBbls, which accounts for more than half of our total proved reserves on a BOE basis. The 2009 tertiary proved reserve additions were primarily at Cranfield and Eucutta Field. In order to recognize proved reserves,

Tertiary Oil Reserves
MMBOE



we must either have an oil production response from CO_2 injections or the field must be analogous to another producing tertiary oil field in the same area.

The main features of our CO_2 EOR program are low cost reserve additions and steady production growth. We estimate that in addition to our 135 MMBbls of proved oil reserves from CO_2 EOR operations, our nine phases contain 368 MMBbls of potential reserves for a total of approximately 503 MMBbls in the Gulf Coast region. We estimate that proved CO_2 reserves at Jackson Dome are nearly sufficient to recover these proved and potential oil reserves. Our business model provides for the development of these additional potential CO_2 EOR reserves over the next several years, and we expect our tertiary oil production to increase over that period of time by an average of 10% to 20% per year. This forecast is dependent, however, on our capability to invest capital dollars in our projects which is highly dependent on the level of commodity prices.

Anthropogenic CO_2 Volumes

Our strategy is to augment our natural CO_2 volumes with anthropogenic volumes from power plants or other industrial plants. As we discussed earlier, our ability to do this is largely dependent on the construction of new gasification facilities, or CO_2 capture facilities at existing sites. The timing of this construction is uncertain, but we anticipate that it is at least three or four years away. This timing could be ideal for us, as it would allow us to expand our CO_2 EOR operations beyond our current phases.

We believe that we offer industrial emitters the most practical and economical way to sequester CO_2, as we can permanently store the CO_2 underground in depleted oil

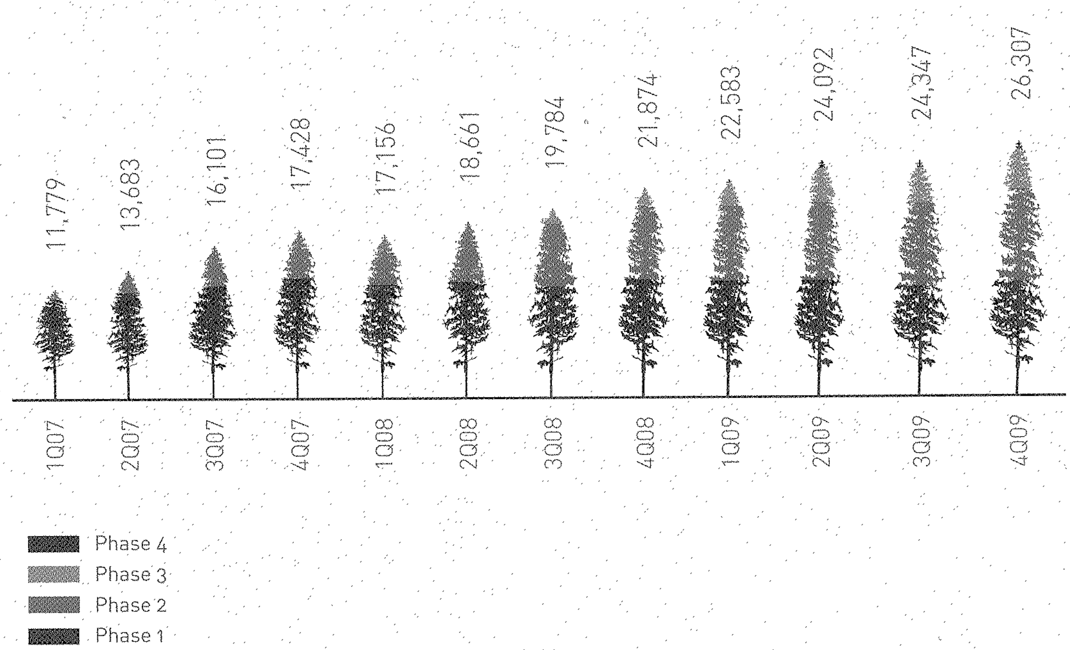
We believe that we offer industrial emitters the most practical and economical way to sequester CO_2, as we can permanently store the CO_2 underground in depleted oil reservoirs.

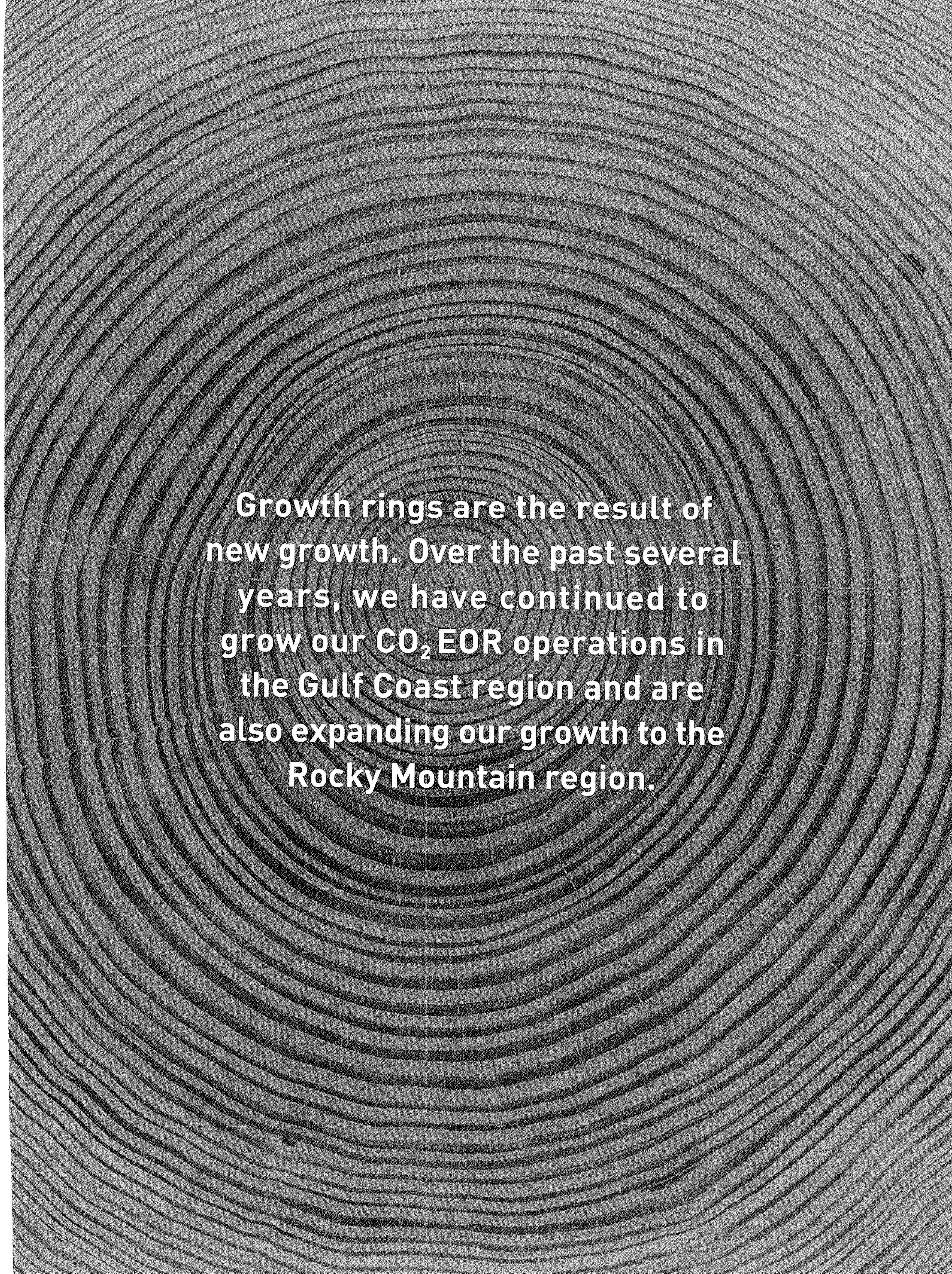
3

CO_2 Enhanced Oil Recovery & Storage

reservoirs. As we have in the past, we continue to work with the appropriate government entities to certify our oil fields as permanent sequestration sites to ensure we are able to utilize any tax credits or carbon credits that may become available. In summary, we believe that we can create value from a product like CO_2, which others may view as a waste or liability.

Average Net Daily Tertiary Oil Production
Bbls




Growth rings are the result of new growth. Over the past several years, we have continued to grow our CO_2 EOR operations in the Gulf Coast region and are also expanding our growth to the Rocky Mountain region.

4

CO_2 Strategic Benefits

Benefits of Denbury's Strategy

Denbury's current 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. Assuming that we use anthropogenic CO_2, our 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. Today, we are using CO_2 from our natural source at Jackson Dome but plan to use anthropogenic CO_2 in the future. Not all of the oil that we produce is consumed in such a way that creates CO_2 — a significant percentage is used to produce valuable products like plastics that are used to produce products vital to the modern economy. In any event, oil produced from CO_2 EOR using anthropogenic CO_2 certainly has a lower carbon footprint than imported oil, which most likely sequesters no CO_2 volumes.

CO_2 EOR can recover billions of barrels of oil from existing U.S. oil fields. This additional domestic production can be recovered with little if any additional environmental impacts and many times can be developed more rapidly than many remote exploration prospects. In addition, the CO_2 that is released from the oil can be offset by the CO_2 injected in the CO_2 EOR process, versus no CO_2 offset for imported oil.

The benefits of producing a barrel of oil domestically are very significant to the local and federal economy. In Mississippi, we expect that approximately 50% of the state's total 2010 production of oil will come from CO_2 EOR. Both our capital expenditures and operating expenditures are spent in the local communities where we work and invest, and we contribute to the local and state economies through the various taxes that we pay. Contrast this to the economic cost of imported oil, which provides none of the previously described benefits.

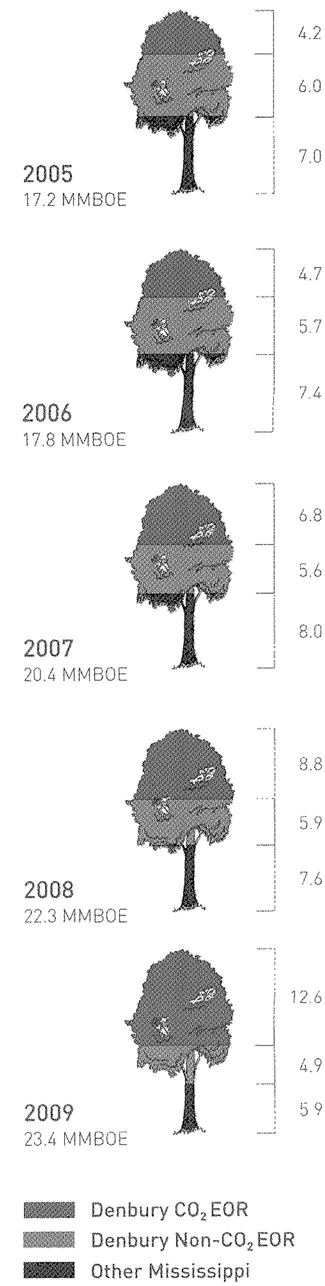
Denbury's current and proposed CO_2 pipeline network will enable commercial-scale carbon capture and storage (CCS) during enhanced oil recovery and potentially in post-production utilization of underlying saline formations. CO_2 pipeline networks provide the infrastructure needed for development of carbon solutions for environmentally sensitive industrial developments, including innovative gasification projects that can produce transportation fuels, power, substitute natural gas, fertilizer and chemicals from plentiful U.S. natural resources.

Older, depleted U.S. oil fields that we acquire often suffer from mechanical or environmental conditions that we remedy as part of our CO_2 EOR operations. Denbury's program to rejuvenate these fields and increase oil production from marginal oil fields begins by initiating 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. Reactivating and increasing oil production in marginal 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.

Denbury's CO_2 EOR efforts in Mississippi are primarily responsible for Mississippi being one of few states with increasing oil production. CO_2 EOR has increased as a total percentage of Mississippi's oil production from less than 5% to over 50% today.

Denbury enjoys being a part of the communities in which we work. Our employees are encouraged to give generously to charitable organizations and educational institutions of their choice with Denbury supporting their efforts through a matching gifts program.

Mississippi Annual Oil Production[1]
MMBOE



[1] Source: Mississippi Oil & Gas Board for state total annual oil production amounts

Board of Directors

Board of Directors
From left to right

David I. Heather
Independent Consultant
Dallas, Texas

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

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

Gareth Roberts
Co-Chairman of the Board, and Chief Strategist
Principal
Scarab Operating Company
Plano, Texas

Ronald G. Greene
Principal
Tortuga Investment Corp.
Calgary Alberta

Michael B. Decker
Principal
Wingate Partners
Dallas, Texas

Randy Stein
Independent Consultant
Denver, Colorado

Gregory L. McMichael
Independent Consultant
Denver, Colorado

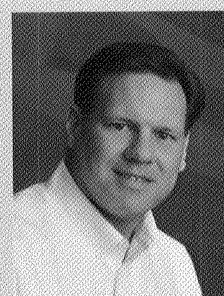
Our corporate governance guidelines, as well as the charters for our nominating/governance committee, compensation committee, and audit committee are listed on the Company website at www.denbury.com. The website also contains other corporate governance information such as our code of ethics for our directors, 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.

Management

Phil Rykhoek +
Chief Executive Officer

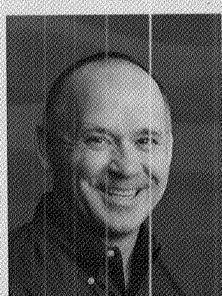
Ronald T. Evans +
President & Chief Operating Officer



Mark C. Allen +
Senior Vice President & Chief Financial Officer

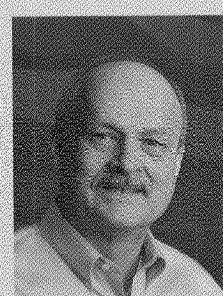
Robert Cornelius +
Senior Vice President, Operations

Dan E. Cole
Vice President, Marketing



Bradley A. Cox
Vice President, Business Development

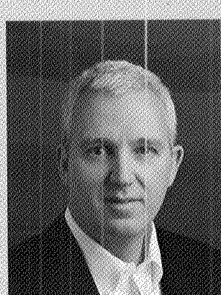
Greg Dover
Vice President, North Region



Ray Dubuisson
Vice President, Legal

Charlie Gibson
Vice President, West Region

Jeff Marcel
Vice President, Drilling

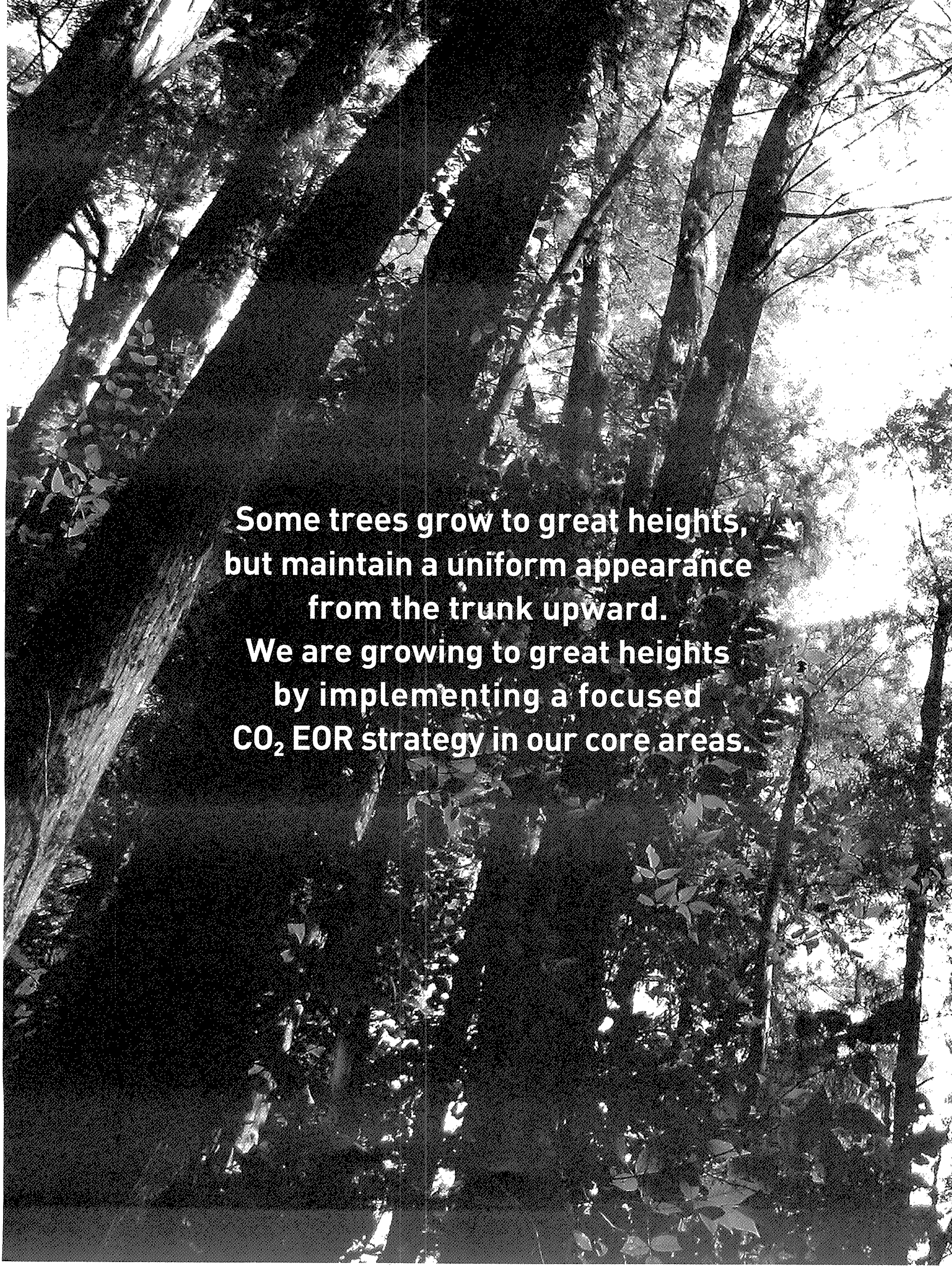


Alan Rhoades
Vice President, Accounting

Barry Schneider
Vice President, East Region

Whitney Shelley
Vice President, Human Resources

+ Member of Investment Committee


Some trees grow to great heights,
but maintain a uniform appearance
from the trunk upward.
We are growing to great heights
by implementing a focused
CO_2 EOR strategy in our core areas.

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

2009 FORM 10-K

(Mark One)

_X_ Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2009
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.)*
5100 Tennyson Parkway, Suite 1200, Plano, TX	**75024**
(Address of principal executive offices)	*(Zip Code)*

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

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

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate 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 _X_ No ___

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

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 _X_ 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 _X_

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 $2,625,591,935.

The number of shares outstanding of the registrant's Common Stock as of January 31, 2010, was 262,364,085.

DOCUMENTS INCORPORATED BY REFERENCE

Document:	Incorporated as to:
1. Notice and Proxy Statement for the Annual Meeting of Shareholders to be held May 19, 2010.	*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 or CO_2.
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.
Finding and Development Cost	The average cost per BOE to find and develop proved reserves during a given period. It is calculated by dividing costs, which includes the total acquisition, exploration and development costs incurred during the period plus future development and abandonment costs related to the specified property or group of properties, by the sum of (i) the change in total proved reserves during the period plus (ii) total production during that period.
MBbls	One thousand barrels of crude oil or other liquid hydrocarbons.
MBOE	One thousand BOEs.
Mbtu	One thousand Btus.
Mcf	One thousand cubic feet of natural gas or CO_2.
Mcf/d	One thousand cubic feet of natural gas or CO_2 produced per day.
Mcfe	One thousand 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.
Mcfe/d	Mcfes 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 or CO_2.
MMcf/d	One million cubic feet of natural gas or CO_2 per day.
MMcfe	One thousand Mcfe.
MMcfe/d	MMcfes produced per day.
PV-10 Value	When used with respect to oil and natural gas reserves, PV-10 Value means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated future production, development and abandonment costs, and before income taxes, discounted to a present value using an annual discount rate of 10%. PV-10 Values calculated as of December 31, 2009 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices on the first day of each month within a 12-month period ended December 31, 2009. PV-10 Values calculated prior to December 31, 2009 were prepared using prices and costs in effect at the determination date. PV-10 Value is a non-GAAP measure and its use is further discussed in footnote 4 to the table on page 24.
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 crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.
Proved Undeveloped Reserves*	Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required.
Tcf	One trillion cubic feet of natural gas or CO_2.

* This definition is an abbreviated version of the complete definition as defined by the SEC in Rule 4-10(a) of Regulation S-X. For the complete definition see: http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?type=simple;c=ecfr;cc=ecfr;sid=9cb6302b536b7a2f8af3f13fc182642a;region=DIV1;q1=regulation%20s-x;rgn=div7;view=text;idno=17;node=17%3A2.0.1.1.8.0.21

ITEM 1. BUSINESS

WEBSITE ACCESS TO REPORTS

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 COMPANY

Denbury Resources Inc. is a Delaware corporation organized under *Delaware General Corporation Law* ("DGCL") and is engaged in the acquisition, development, operation and exploration of oil and natural gas properties in the Gulf Coast region of the United States, primarily in Mississippi, Louisiana, Texas and Alabama. Our corporate headquarters is located at 5100 Tennyson Parkway, Suite 1200, Plano, Texas 75024, and our phone number is 972-673-2000. At December 31, 2009, we had 830 employees, 492 of whom were employed in field operations or at the field offices. Our employee count does not include the approximately 675 employees of Genesis Energy, LLC as of December 31, 2009, as its employees exclusively carry out the business activities of Genesis Energy, L.P., which we do not consolidate in our financial statements. On February 5, 2010, we sold our interest in Genesis Energy, LLC, the general partner of Genesis Energy, L.P. (see Notes 1 and 15 to the Consolidated Financial Statements). On October 31, 2009, we signed a definitive merger agreement to acquire Encore Acquisition Company ("Encore") in a merger, which merger is subject to approval by shareholders of Denbury and Encore and other conditions, is scheduled to close on or about March 9, 2010.

Incorporation and Organization

Denbury was originally incorporated in Canada in 1951. In 1992, we acquired all of the shares of a United States operating company, Denbury Management, Inc. ("DMI"), and subsequent to the merger we sold all of its Canadian assets. Since that time, all of our operations have been in the United States.

In April 1999, our stockholders approved a move of our corporate domicile from Canada to the United States as a Delaware corporation. Along with the move, our wholly owned subsidiary, DMI, was merged into the new Delaware parent company, Denbury Resources Inc. This move of domicile did not have any effect on our operations or assets.

Effective December 29, 2003, Denbury Resources Inc. changed its corporate structure to a holding company format. As part of this restructure, Denbury Resources Inc. (predecessor entity) merged into a newly formed limited liability company, and survived as Denbury Onshore, LLC, a Delaware limited liability company and an indirect subsidiary of the newly formed holding company, Denbury Holdings, Inc. Denbury Holdings, Inc. subsequently assumed the name Denbury Resources Inc. Stockholders' ownership interests in the business did not change as a result of the new structure and shares of the Company continue to trade publicly under the same symbol (DNR) on the New York Stock Exchange.

BUSINESS STRATEGY

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

- remain focused 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.

DEFINITIVE MERGER AGREEMENT TO ACQUIRE ENCORE ACQUISITION COMPANY.

On November 1, 2009, Denbury and Encore Acquisition Company (NYSE: EAC) ("Encore") announced that we had entered into a definitive merger agreement providing for Encore to merge with and into Denbury, in a stock and cash transaction valued at approximately $4.5 billion at that time, including the assumption of debt and the value of the noncontrolling interest in Encore Energy Partners LP (NYSE: ENP) ("Encore MLP"). The combined company will continue to be known as Denbury Resources Inc. and will be headquartered in Plano, Texas.

The Agreement and Plan of Merger by and between Denbury and Encore dated October 31, 2009 (the "Merger Agreement") was unanimously approved by the boards of directors of both Denbury and Encore. The Merger Agreement contemplates a merger (the "Merger") whereby Denbury and Encore have agreed to combine their businesses such that Encore will be merged with and into Denbury, with Denbury surviving the Merger. The Merger is subject to the stockholders of each of Denbury and Encore approving the Merger, including approval by Denbury's stockholders of the issuance of Denbury common stock to be used as Merger consideration. Each company has scheduled a special stockholder meeting on March 9, 2010, for stockholders to vote on the Merger.

Encore is engaged in the acquisition and development of oil and natural gas reserves from onshore fields in the United States. Encore's properties and oil and gas reserves are located in four core areas: the Cedar Creek Anticline in the Williston Basin in Montana and North Dakota; the Permian Basin in west Texas and southeastern New Mexico; the Rocky Mountain region, which includes non-Cedar Creek Anticline assets in the Williston, Big Horn and Powder River Basins in Wyoming, Montana and North Dakota and the Paradox Basin in southeastern Utah; and the Mid-Continent region, which includes the Arkoma and Anadarko Basins in Oklahoma, the North Louisiana Salt Basin and the East Texas Basin.

The acquisition by Denbury of Encore positions the combined company as one of the largest crude oil-focused, independent North American exploration and production companies, with oil constituting approximately 75% of its combined proved reserves and with future growth predominantly in oil. The acquisition also creates one of the largest CO_2 EOR platforms in both the Gulf Coast and Rocky Mountain regions, complemented by Denbury's ownership and control of the Jackson Dome CO_2 source in Mississippi and CO_2 supply contracts with potential anthropogenic sources of CO_2 in the Gulf Coast, Midwest and Rockies. Denbury expects the combined company's size and scale, access to capital and geographic presence to facilitate larger CO_2 projects, additional property acquisitions and opportunities to partner with CO_2 emitters, in both the Gulf Coast and Rocky Mountain regions. The combined company will nearly double Denbury's inventory of oil reserves (prior to the Conroe acquisition) potentially recoverable with CO_2 tertiary operations. Denbury believes that the longer lead-time of CO_2 project development in the Rocky Mountain region, where Encore's legacy oil assets are distinguished by their long reserve lives and low decline rates, is well-matched with a strong growth profile from low-risk development of unconventional resource plays in Encore's large acreage positions in the Bakken oil shale in North Dakota and positions in the Haynesville shale in north Louisiana.

For more information regarding Encore, its properties and the reasons for the merger, please see Encore's 2009 Form 10-K filed with the SEC on February 25, 2010, and our joint proxy statement/prospectus dated February 5, 2010.

Merger Agreement

Under the Merger Agreement, Encore stockholders will receive $50.00 per share for each share of Encore common stock, comprised of $15.00 in cash and $35.00 in Denbury common stock, subject to both an election feature and a collar mechanism on the stock portion of the consideration as set forth in more detail below.

Exchange Ratio

In calculating the exchange ratio range for the collar mechanism, the Denbury common stock was initially valued at $15.10 per share. The collar mechanism is limited to a 12% upward or downward movement in the Denbury share price. The final number of Denbury shares to be issued will be adjusted based on the volume weighted average price of Denbury common stock on the NYSE for the 20-day trading period ending on the second day prior to closing. Based on this mechanism, if Denbury stock trades between $13.29 and $16.91, the Encore stockholders will receive between 2.0698 and 2.6336 shares of Denbury common stock for each of their shares of Encore common stock, but not higher or lower than these share amounts if Denbury common stock trades outside this range. If Denbury common stock trades outside of this range, the value of the shares of Denbury received will represent either more or less than $35 per share.

Encore stockholders will also have an option to elect to receive all stock or all cash, subject to a proration feature, such that if Denbury stock trades within this range, the overall mix of consideration will be 70% Denbury common stock and 30% cash in the aggregate. Subject to proration, Encore stockholders electing to receive all cash will receive $50 per share in cash, and Encore stockholders electing to receive only Denbury common stock will receive for each Encore share between 2.9568 and 3.7622 shares of Denbury common stock. In addition, upon completion of the Merger, all Encore stock options will fully vest and their value will be paid in cash. All Encore restricted stock will vest and each holder will have the opportunity to make the same elections as other holders of Encore common stock as described above, except for shares of Encore restricted stock granted as a 2009 bonus pursuant to the Encore annual incentive program, which will be converted into restricted shares of Denbury common stock.

Covenants

The Merger Agreement contains customary covenants by each party to the Merger Agreement. Such covenants include, among others, covenants that, prior to the effective time of the Merger, both Denbury and Encore will operate their respective businesses in the ordinary course and in a manner consistent with past practices, subject to limited exceptions, and covenants by both Denbury and Encore that their respective boards of directors not change their recommendations to the stockholders of each of them to vote in favor of the Merger, subject to exceptions specified in the Merger Agreement. Encore has also agreed not to solicit or initiate discussions with third parties regarding other proposals to acquire Encore and to certain restrictions on its ability to respond to any such proposal.

Conditions to Closing

Consummation of the Merger is subject to customary conditions, including, among others, (a) the adoption of the Merger Agreement by the requisite approval of the stockholders of both Denbury and Encore, (b) the absence of any material adverse effect, (c) the absence of any order or injunction prohibiting the consummation of the Merger, (d) the approval of the listing of the shares of Denbury common stock to be issued in the Merger on the New York Stock Exchange, (e) the accuracy of the parties' respective representations and warranties as set forth in the Merger Agreement, subject, as to certain of the representations and warranties as specified in the Merger Agreement, to materiality, (f) the receipt of legal opinions stating, among other things, that the Merger will constitute a reorganization under Section 368(a) of the Internal Revenue Code of 1986, as amended, and (g) the receipt of all approvals or reviews required by federal and state regulatory authorities.

Financing of the Merger

We received a financing commitment from J.P. Morgan, subject to customary conditions, to underwrite a new $1.6 billion senior secured revolving credit facility. We have been advised by the co-arrangers of this new senior secured revolving credit facility, J.P. Morgan and Bank of America, N.A., that the syndication phase is complete, and documentation for this facility is being prepared. Subject to final documentation and satisfaction of closing conditions, we anticipate finalizing this facility prior to the Denbury and Encore stockholder meetings. The newly committed financing, coupled with the funds from our recent senior subordinated debt offering (see next paragraph), will be used to fund the cash portion of the merger consideration (inclusive of payments due to Encore stock option holders), repay amounts outstanding under our existing $750 million revolving credit facility, which had $125 million outstanding as of February 15, 2010, potentially retire and replace up to $825 million of Encore's senior subordinated notes that are outstanding, all of which have a change of control put option at 101% of par value, repay amounts outstanding under Encore's existing revolving credit facility which had $155 million outstanding as of February 15, 2010, pay Encore's severance costs, pay transaction fees and expenses and provide additional liquidity. The aggregate commitment of the senior secured lenders is a $1.6 billion facility with a term of four years. The new facility is expected to be on substantially the same terms as our existing facility, conformed to current market conditions.

We also received a financing commitment from J.P. Morgan for a $1.25 billion unsecured bridge loan facility; however, this bridge loan facility has been terminated and will not be utilized to fund the Merger as we have instead issued $1 billion of 8.25% Senior Subordinated Notes due 2020. On February 10, 2010, we sold $1 billion of 8.25% Senior Subordinated Notes due 2020 at 100% of par in a public offering. The net proceeds from the notes offering were placed in escrow pending the closing of the Merger, subject to mandatory redemption of the notes if the Merger does not close, and partial redemption of the notes to the extent that three series of Encore outstanding senior subordinated notes are not repurchased. Upon the closing of the Merger, $400 million of the escrowed proceeds will be released to us to finance a portion of the merger consideration, and the remaining amount of escrowed proceeds will be used to fund repurchases of up to $600 million principal amount of three series of Encore's outstanding senior subordinated notes (or newly issued 8.25% senior notes to the extent not issued to repurchase Encore notes). On February 8, 2010, we initiated a tender offer for these Encore subordinated notes, the closing of which is subject to closing of the Merger.

We also received a financing commitment from J.P. Morgan and JPMorgan Chase to fund a new $375 million senior secured revolving credit facility to replace an existing senior secured revolving credit facility of Encore Energy Partners Operating LLC, a subsidiary of ENP, if required to allow for the Merger. On November 24, 2009, ENP obtained an amendment to its existing revolving credit facility to allow for the Merger; consequently this third financing commitment will not be used.

Fee letters executed in connection with the financing commitments require Denbury to pay up to approximately $48 million in fees if the Merger does not close.

Termination

The Merger Agreement contains certain termination rights for both us and Encore, including, among others, if the Merger has not occurred on or before May 31, 2010. On a termination of the Merger Agreement under certain circumstances, Encore may be required to pay us a termination fee of either $60 million or $120 million, or we may be required to pay Encore a termination fee of either $60 million, $120 million or $300 million, in each case depending on the circumstances of the termination. In addition, Encore is obligated to reimburse us for up to $10 million of our expenses related to the Merger if specified termination events occur.

OTHER ACQUISITIONS

Information as to recent acquisitions and divestitures by Denbury is set forth under Note 2, "Acquisitions and Divestitures," to the Consolidated Financial Statements.

OIL AND NATURAL GAS OPERATIONS

Our CO_2 Assets

Overview. Since we acquired our first carbon dioxide tertiary flood in Mississippi in 1999, we have gradually increased our emphasis on these types of operations. During this time, we have learned a considerable amount about tertiary operations and working with carbon dioxide. Our tertiary operations have grown to the point that approximately 65% of our December 31, 2009 proved reserves are proved tertiary oil reserves, almost 65% of our forecasted 2010 production is expected to come from tertiary oil operations (on a BOE basis), and almost all of our 2010 capital expenditures are related to our current or future tertiary operations. We particularly like this play as (i) it has a lower risk as we are working with oil fields that have significant historical production and data, (ii) it provides a reasonable rate f return at relatively low oil prices (we estimate our economic break-even before corporate overhead and expenses on these projects at current oil prices is in the range of the mid-thirties, depending on the specific field and area), and (iii) we have limited competition for this type of activity in our geographic areas. Generally, from East Texas to Florida, there are no known significant natural sources of CO_2 in the Gulf Coast area except our own, and these large volumes of CO_2 that we own drive the play. In addition, 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 provide an economical way to sequester CO_2. We have acquired several old oil fields in our areas of operations with potential for tertiary recovery and plan to acquire additional fields, and we are continuing to expand our CO_2 pipeline infrastructure to transport CO_2.

During 2009, we added 17.6 MMBbls of tertiary-related proved oil reserves, primarily initial proven tertiary oil reserves at Cranfield Field (Phase 4), (see discussion of the individual fields below), increasing our proved tertiary oil reserves from 125.8 MMBbls at December 31, 2008 to 134.5 MMBbls as of December 31, 2009. In order to recognize proved tertiary oil reserves, we must either have an oil production response to the 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 associated production response.

CO_2 used in enhanced oil recovery ("EOR") is one of the most efficient tertiary recovery mechanisms for crude oil. The CO_2 acts somewhat like a solvent for the oil, removing it from the oil-bearing formation as the CO_2 passes through the rock. CO_2 tertiary floods are unique because they require large volumes of CO_2, the location of which, to our knowledge, is limited to a few geological basins, one of which is our source near Jackson, Mississippi. The most efficient way to transport CO_2 is via dedicated pipelines, which are also in limited supply. Because the sources and methods of transportation of CO_2 are limited, only 5% or approximately 250,000 Bbls/d of the United States domestic oil production is derived from tertiary recovery projects.

Our CO_2 source field, Jackson Dome, located near Jackson, Mississippi, was discovered during the 1970s while being explored for hydrocarbons. This significant source of CO_2 is the only known one of its kind in the United States east of the Mississippi River. Mississippi's first enhanced oil recovery project began in the mid 1980s in Little Creek Field following the installation of Shell Oil Company's Choctaw CO_2 Pipeline. The 183-mile Choctaw Pipeline (now referred to as NEJD Pipeline) transported CO_2 produced from Jackson Dome to Little Creek Field. While the CO_2 flood proved successful in recovering significant amounts of oil, commodity prices at that time made the project unattractive for Shell and they later sold their oil fields in this area, as well as the CO_2 source wells and pipeline.

While enhanced oil recovery projects utilizing CO_2 may not be considered a new technology, Denbury applies several additional technologies to the fields: well evaluations, new completion or stimulation techniques, operating equipment and seismic interpretations. 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 NEJD pipeline in 2001. Based upon our success at Little Creek, we embarked upon a strategic program to improve our understanding and knowledge of CO_2 production and tertiary recovery to build a dominant position in this enhanced oil play.

Tertiary Recovery Phases. We categorize our tertiary operations by labeling operating areas or groups of fields as phases.

- Phase 1 includes several fields along our 183-mile NEJD CO_2 Pipeline that runs through southwest Mississippi and into Louisiana. The most significant fields in this area are Little Creek, Mallalieu, McComb, and Brookhaven Fields, all fields which have been producing oil for some time, and one of our newer enhanced oil fields, Lockhart Crossing Field. We saw our first tertiary oil production from Lockhart Crossing Field, located in South Louisiana, during 2008. Lockhart Crossing, although a relatively small field, was the first of three fields to be CO_2 flooded in Louisiana and is our first flood outside the state of Mississippi. Although Phase 1 fields have been producing for some time, they accounted for approximately 50% of our total 2009 CO_2 EOR production.

- Phase 2, which began with the early 2006 completion of the Free State CO_2 Pipeline to East Mississippi, includes Eucutta, Soso, and Martinville Fields which have been producing oil for over three years, and Heidelberg Field where we started injecting CO_2 in December 2008. Heidelberg had its first EOR production response to CO_2 injections during May 2009.

- Phase 3, Tinsley Field, located northwest of Jackson, Mississippi, acquired in January 2006, is serviced by the Delta CO_2 Pipeline completed in January 2008. Tinsley Field had its first oil production response in the second quarter of 2008.

- Phase 4 includes Cranfield, where we began CO_2 injection operations during July 2008 and had our first oil production response in the first quarter of 2009, and Lake St. John Field, a project currently scheduled to commence during 2011 or 2012. Both Phase 4 fields are located near the Mississippi/Louisiana border, near Natchez, Mississippi.

- Phase 5 is Delhi Field, a Louisiana field acquired in 2006, located southwest of Tinsley Field and east of Monroe, Louisiana. CO_2 injection in Delhi Field began during the fourth quarter of 2009, following completion of an additional 81-mile segment of the Delta CO_2 Pipeline. We expect our first oil production response to CO_2 injection at Delhi Field by mid-2010.

- Phase 6 is Citronelle Field in Southwest Alabama, another field acquired in 2006. Citronelle will require an extension to the Free State CO_2 Pipeline, or a man-made source of CO_2 in order to commence this project, the timing of which is uncertain at this time.

- Phases 7 and 8 will require completion of our 320-mile Green Pipeline, which will run from Southern Louisiana to Hastings Field, south of Houston, Texas, and is scheduled for completion late 2010. Hastings Field, a field on which we acquired a purchase option late 2006 and purchased in February 2009, is our Phase 7, the Seabreeze Complex (Oyster Bayou Field), acquired in 2007, will be our Phase 8. We expect to commence CO_2 injections at Oyster Bayou Field in mid-2010 and at Hastings field in early 2011.
- Phase 9 is Conroe Field, acquired in December 2009.

Jackson Dome. In February 2001, we acquired approximately 800 Bcf of proved producing CO_2 reserves for $42 million, a purchase that gave us control of most of the CO_2 supply in Mississippi, as well as ownership and control of a critical 183-mile CO_2 pipeline. This acquisition provided the platform to significantly expand our CO_2 tertiary recovery operations by assuring that CO_2 would be available to us on a reliable basis and at a reasonable and predictable cost. Since February 2001, we have acquired two wells and drilled 21 additional CO_2 producing wells, significantly increasing our estimated proved CO_2 reserves to approximately 6.3 Tcf as of December 31, 2009, which is almost enough for our existing and currently planned phases of operations. The estimate of 6.3 Tcf of proved CO_2 reserves is based on 100% ownership of the CO_2 reserves, of which Denbury's net ownership (net revenue interest) is approximately 5.0 Tcf and is included in the evaluation of proved CO_2 reserves prepared by DeGolyer and MacNaughton. In discussing our available CO_2 reserves, we make reference to the gross amount of proved reserves, as this is the amount that is available both for Denbury's tertiary recovery programs and for industrial users who are customers of Denbury and others, as Denbury is responsible for distributing the entire CO_2 production stream.

Although our current proved and potential CO_2 reserves are quite large, in order to continue our tertiary development of oil fields in the area, incremental deliverability of CO_2 is required. In order to obtain additional CO_2 deliverability, we continued our exploration efforts by evaluating a 136-square-mile 3-dimensional seismic program during 2009. The 3-D seismic program, located west of the DRI Ice Field, was acquired during 2008 over existing known CO_2 fields and adjacent lead areas. We anticipate drilling three wells during 2010, one or two of which will be exploratory wells based upon the interpretation of the seismic data. During 2009, we drilled and completed one additional CO_2 production well. The 2009 well added approximately 340 Bcf of additional CO_2 reserves and increased our estimated Jackson Dome total CO_2 production capacity to approximately 1.0 Bcf/d. Additional CO_2 reserves were added by acquiring additional proved non-producing acreage over one of our existing fields. In addition to increasing our proved reserves by 0.9 Bcf (after the effect of 2009 production), and in order to ensure future production rates, processing capabilities and deliverability to our fields, during 2009 we constructed a 150 MMcf/d dehydration facility, installed additional pump capacity at the Brandon Pump Station and constructed a 14-mile pipeline from the Barksdale dehydration facility to the Brandon Pump Station. This 14-mile Brandon pipeline and pump station will provide additional capacity to the southern end of the NEJD Pipeline.

During 2009, we sold an average of 88 MMcf/d of CO_2 to commercial users, and we used an average of 595 MMcf/d for our tertiary activities. We are continuing to increase our CO_2 production, which averaged 790 MMcf/d during the fourth quarter of 2009, a 3% increase over the fourth quarter of 2008 production levels. We estimate that our planned tertiary operations will not require any significant additional deliverability through 2010 above the production capacity of 1.0 Bcf/d.

Man-made CO_2 Sources. In addition to our natural source of CO_2, we have entered into long-term contracts to purchase man-made CO_2 from eight proposed plants that will emit large volumes of CO_2, four of which are in the Gulf Coast region and four in the Midwest region (Illinois, Indiana and Kentucky.) The Midwest purchases are conditioned on both the specific plant being constructed and Denbury contracting enough volumes of CO_2 for purchase in the general area of our proposed Midwest pipeline system, such that an acceptable economic rate-of-return on the CO_2 pipeline will be achieved. If all eight of these plants were to be built, these CO_2 sources are currently anticipated to provide us with aggregate CO_2 volumes of 1.2 Bcf/d to 1.9 Bcf/d, although the earliest source of this man-made CO_2 is not expected to be available to us until 2014. These plants have all been delayed due to current economic conditions and there is some doubt as to whether they will be constructed at all. Several of these plants are seeking funds from government sources, which if secured, could increase the probability that the plants are ultimately constructed.

The base price of CO_2 per Mcf from these CO_2 sources varies by plant and location, but is generally higher than our most recent "all-in" cost of CO_2 from our natural source (Jackson Dome) using current oil prices. Prices for CO_2

delivered from these projects are expected to be competitive with the cost of our natural CO_2 after adjusting for our share of potential carbon emissions reduction credits using estimated futures prices of carbon emissions reduction credits. If all eight plants are built, the aggregate purchase obligation for this CO_2 would be around $280 million per year, assuming a $70 per barrel oil price, before any potential savings from our share of carbon emissions reduction credits. All of the contracts have price adjustments that fluctuate based on the price of oil. Construction has not yet commenced on any of these plants, and their construction is contingent on the satisfactory resolution of various issues, including financing. While it is likely that not every plant currently under contract will be constructed, there are several other plants under consideration that could provide CO_2 to us that would either supplement or replace some of the CO_2 volumes from the eight proposed plants for which we currently have CO_2 output purchase contracts. We are having ongoing discussions with several of these other potential sources.

CO_2 Pipelines. We acquired the NEJD 183-mile CO_2 pipeline that runs from Jackson Dome to near Donaldsonville, Louisiana, as part of the 2001 acquisition of our Jackson Dome source field (see above). Construction of our Free State Pipeline was completed in 2006 and it is currently transporting CO_2 to our four existing Phase 2 tertiary fields in East Mississippi (Eucutta, Soso, Martinville and Heidelberg) and will also be used for our proposed projects at South Cypress Creek and other fields in Phase 2.

During 2008, we continued our expansion of our CO_2 pipeline infrastructure with the completion of the first segment of our Delta Pipeline between Jackson Dome and Tinsley Field in January (31 miles), which significantly increased the transportation capacity of CO_2 to that field. We also reconditioned and converted the natural gas pipeline we acquired from Southern Natural Gas Company in 2007 to CO_2 service, which we are currently using to transport CO_2 to our first Phase 4 field, Cranfield Field. During 2009, we completed construction on the 68-mile extension of the Delta Pipeline from Tinsley Field to Delhi Field.

In late 2006, we purchased an option to acquire Hastings Field, a potential tertiary flood located near Houston, Texas, which we subsequently acquired in February 2009. In order to flood Hastings Field, we are building a CO_2 pipeline from the southern end of our existing NEJD CO_2 Pipeline that terminates near Donaldsonville, Louisiana, to Hastings Field, estimated to be approximately 320 miles (the "Green Pipeline"). Based on our latest estimates, this pipeline is expected to cost between $850 million and $875 million. Our efforts during 2007 and 2008 were focused on engineering design, pipe manufacturing and right-of-way acquisitions. Construction of the pipeline began during November 2008 near Donaldsonville, Louisiana, and was "welded-out" to Oyster Bayou Field, near Houston, Texas, in December 2009. Construction will continue during 2010 to complete the final segments of the pipeline from Oyster Bayou to Hastings Field (approximately 53 miles). Construction crews will complete the pipeline and its connecting line to Oyster Bayou Field, east of Galveston Bay, in early 2010 and on to Hastings Field by year-end 2010. Initially, we anticipate transporting CO_2 from our natural source at Jackson Dome on this line, but ultimately we expect that it will be used to ship predominately man-made (anthropogenic) sources of CO_2.

Overall tertiary economics. When we began our tertiary operations several years ago, they were generally economic at oil prices below $20 per Bbl, although the economics varied by field. Our costs have escalated during the last few years due to general cost inflation in the industry and higher oil prices, and we estimate that our current economic break-even, before corporate overhead and interest, is in the mid-thirties per barrel if oil prices remain at their current level. Our inception-to-date finding and development costs (including future development and abandonment costs but excluding expenditures on fields without proved reserves) for our tertiary oil fields through December 31, 2009, are approximately $12.68 per BOE. Currently, we forecast that our finding and development costs for most of our tertiary projects will average less than $10 per BOE over the life of each field, depending on the state of a particular field at the time we begin operations, the amount of potential oil to be recovered, the proximity to a pipeline or other facilities, and other factors. The finding and development costs to date do not include additional probable reserves in fields with current proved reserves. Our operating costs for tertiary operations are highly dependent on commodity prices and could range from $15 per BOE to $25 per BOE over the life of each field, again depending on the specific field.

While these economic factors have wide ranges, our rate of return from these operations has generally been better than our rate of return on traditional oil and natural gas operations, and thus our tertiary operations have become our single most important focus area. While it is extremely difficult to accurately forecast future production, we do believe that our tertiary recovery operations provide significant long-term production growth potential at reasonable rates of return, with relatively low risk, and thus will be the backbone of our Company's growth for the foreseeable future. Although we believe that our plans and projections are reasonable and achievable, there could be delays or unforeseen problems in the future that could delay or affect the economics of our overall tertiary development program. We believe that such delays or price effects, if any, should only be temporary.

Tentatively, we plan to invest approximately $74 million in 2010 in the Jackson Dome area to drill three additional wells, install additional pump stations and gathering lines for discovery wells drilled during the period. These investments will add CO_2 deliverability for future operations along the Gulf Coast. Approximately $365 million in capital expenditures is budgeted in 2010 at the oil field level in Phases 1 through 9, plus an additional $159 million for CO_2 pipelines, making our combined CO_2 related expenditures just over 90% of our projected $650 million 2010 capital budget, before consideration of capital expenditures to be incurred on Encore properties if the proposed acquisition of Encore is completed.

Our Tertiary Oil Fields with Proved Tertiary Reserves

On December 31, 2009, we had total tertiary-related proved oil reserves of approximately 134.5 MMBbls, as further outlined on the table under "Item 1. Field Summaries." Overall, our production from tertiary operations has increased from approximately 1,350 Bbls/d in 1999, the then existing production at Little Creek Field at the time of acquisition, to an average of 26,307 Bbls/d during the fourth quarter of 2009. We expect this production to continue to increase for several years as we expand our tertiary operations to additional fields.

Phase 1 Fields

Mallalieu Field. Mallalieu Field consists of two units, West Mallalieu Unit and the smaller East Mallalieu Unit. Our initial injections of CO_2 commenced in 2001 and our first oil production from EOR commenced in 2002. Mallalieu field is currently our most prolific tertiary flood in terms of production, producing 4,005 Bbls/d during the fourth quarter of 2009, although we believe that the production at this field has peaked and is expected to generally decline in the future as the field is essentially fully developed. In contrast to many of our existing fields, Mallalieu Field was not waterflooded prior to CO_2 injection. Therefore, we estimate that the tertiary recovery of oil from Mallalieu Field as a result of CO_2 injection will be higher than the recoveries at other fields. Our December 31, 2009 proved reserves currently project that we will recover an estimated 22% at this field, higher than our 17% recovery factor that we assume for most other fields in this area. A total of $20.1 million was invested in this field during 2009 to improve the compression and fluid handling capabilities at the production facilities. The expansion of the central processing facility in this field increased CO_2 recycle rates from 160 MMcf/d to approximately 230 MMcf/d.

From inception through December 31, 2009, we had net positive cash flow (revenue less operating expenses and capital expenditures, including the acquisition cost) from Mallalieu Field of $464.1 million.

McComb and Smithdale Fields. We commenced tertiary recovery operations in 2003 at McComb Field and started injecting CO_2 late that year. The first production response occurred in the second quarter of 2004 and has generally increased since that time, averaging 2,412 Bbls/d in the fourth quarter of 2009. During 2009, the technical team improved their understanding of the reservoir and increased production rates by monitoring injection patterns, reworking producing wells, and using injection surveys for conformance issues within the reservoir. Our team's efforts lead to increased production without any additional development during 2009. During 2010, the team plans to drill three injection wells and four producing wells and increase CO_2 injection volumes at McComb Field.

The reservoir at Smithdale is channel sand and thus our drilling was based on the interpretation of our 2007 3-D seismic survey covering the McComb and Smithdale Fields. By utilizing the 3-D seismic data, our geoscientists are able to put our wells in optimal positions within the channels at Smithdale to maximize the aerial coverage and sweep of the CO_2 injected. During 2010, we plan to drill two producing wells and one CO_2 injection well based on seismic and reservoir data.

From inception through December 31, 2009, we had not yet recovered our costs in these fields, with net negative cash flow (revenue less operating expenses and capital expenditures, including the acquisition costs) from these fields of $76.9 million.

Brookhaven Field. Our first tertiary CO_2 production response at Brookhaven Field occurred during the fourth quarter of 2005, and has generally increased to an average rate of 3,416 Bbls/d during 2009. Brookhaven Field has three discrete reservoirs that are being simultaneously CO_2 flooded. Our detailed production and reservoir evaluations identified certain areas of high permeability within the Tuscaloosa Reservoir that act as "thief zones" and take a disproportionate volume of CO_2 from the injection wells. Polymer treatments designed to reduce CO_2 injection into these "thief zones" were pumped successfully on two wells. The polymer treatments are designed to alter the injection profiles and improve the reservoir sweep efficiencies in the first and second development areas of Brookhaven Field. We are also considering the use of water during 2010 to further counteract these "thief zones" in an attempt to improve our sweep efficiency, as the initial results from the use of water and microbes at Little Creek Field have been encouraging (see below). Expansion at Brookhaven will continue during 2010, with the drilling of approximately four wells, and the reentry or workover of an additional sixteen wells.

From inception through December 31, 2009, we had net positive cash flow (revenue less operating expenses and capital expenditures, including the acquisition cost) from Brookhaven of $52.3 million.

Little Creek Area. Little Creek field, Denbury's most mature enhanced oil recovery project, was acquired in 1999. During the fourth quarter of 2009, production averaged 1,479 Bbls/d from the Little Creek area, which includes Lazy Creek. During subsequent years we learned and developed three additional units, Little Creek West, Lazy Creek and Lazy Creek West, which combined with Little Creek Field comprise the Little Creek area. Production at Little Creek area began declining during 2006 and is expected to gradually decline in the future, even though we are working to mitigate production declines by monitoring injection patterns, reworking producing wells and using injection surveys to control at which intervals the CO_2 is injected.

A project was initiated in 2008 between Denbury, Mississippi State University, and the U.S. Department of Energy to study the process of alternating CO_2 injection with nutrient-enriched water in a CO_2 injection well to stimulate the growth and development of microbes in the reservoir. The one-year project will monitor injection pressures and offset oil samples for evidence of improved sweep efficiencies within the reservoir as a result of the growth of the microbes. If successful, the technique could be expanded to other portions of the field and to other fields. Our initial results from this study have shown encouraging results.

From inception through December 31, 2009, we had net positive cash flow (revenue less operating expenses and capital expenditures, including the acquisition cost) from Little Creek (including adjoining smaller fields) of $196.5 million.

Lockhart Crossing Field. Lockhart Crossing, located in Livingston Parish, Louisiana, was our first CO_2 project outside of Mississippi. Lockhart Crossing produces from the Wilcox formation at an average depth of 10,200' and has similar reservoir characteristics to the Tuscaloosa formation, which had great success from tertiary flooding at Little Creek and Mallalieu Fields.

We initiated CO_2 injections during December 2007 after completing a six-mile supply line connecting Lockhart Crossing to the NEJD Pipeline. We saw our first tertiary production in July 2008. By the end of 2009, we had completed two of the five development phases in the field and we are using 3-D seismic data to assist us with the remaining development. During the fourth quarter of 2009, production at Lockhart Crossing Field averaged 1,025 Bbls/d. Expansion of the third development phase will be completed during 2010, with the drilling of four wells and the reentry or workover of an additional two wells.

From inception through December 31, 2009, we had not yet recovered our costs in this field, with net negative cash flow (revenue less operating expenses and capital expenditures, including the acquisition costs) from this field of $49.0 million.

Phase 2 Fields

Eucutta Field. The oil production response we have experienced in Eucutta confirmed the results of the pilot project performed in the early 1980s. During the 1980s, Amerada Hess installed an inverted 5-spot injection pilot in the First City Bank sand (one of the Eutaw sands) to test the application of CO_2 flooding. Although the pilot test only covered approximately 20 acres, the pilot was successful in recovering an additional 17% of the original oil in place within the pattern. Based on this success, we designed and constructed a CO_2 flood and facility for the Eucutta Field. Initial well work was completed and CO_2 injection started during the first quarter of 2006. Initial tertiary oil production occurred in the fourth quarter of 2006. During 2009, we developed the remaining injection patterns in the field, and expanded the CO_2 facility. Oil production continued to increase as the Eutaw Reservoir was more fully developed, averaging 3,912 Bbls/d during the fourth quarter of 2009. We anticipate that production from this field has peaked, or is about to peak, as the field is generally fully developed. With the completion of the majority of the field development, our 2010 plans will consist of expanded fluid handling capabilities at the central facility and monitoring compression requirements.

From inception through December 31, 2009, we had net positive cash flow (revenue less operating expenses and capital expenditures, including the acquisition cost) from Eucutta of $71.2 million.

Soso Field. Soso Field, near Laurel, Mississippi, produced from numerous reservoirs during primary production including the Rodessa, Bailey and Cotton Valley sands, all of which we plan to CO_2 flood. We elected to co-develop the Bailey sand and Rodessa sand to accelerate the development of the potential tertiary oil reserves at Soso. In essence, we will flood the Bailey in one portion of the field and the Rodessa in the other, with plans to switch formations when each is depleted. During the first quarter 2006, we initiated our first injections of CO_2 into five Bailey injection wells and initiated injection in the Rodessa during the second quarter of 2006. We saw our first tertiary production in early 2007 from the Bailey and our first response from the Rodessa in the fourth quarter of 2007.

We made significant additions to the CO_2 recycle facility during 2009, increasing the water separation and handling. Once fluid handling capabilities were addressed, several jet pumps were installed which assisted in lifting the water in the wellbore and subsequently increased oil production. The installation of jet pumps is temporary in that as soon as the well begins producing oil, we are able to recover the pump and install the pump in another well if necessary. During the fourth quarter of 2009, production at Soso had increased to 3,224 Bbls/d. Additional compression and handling of recycled CO_2 will be addressed during 2010, along with four workovers and/or recompletions to add another injection pattern.

From inception through December 31, 2009, we had not yet recovered our costs in this field with net negative cash flow (revenue less operating expenses and capital expenditures, including the acquisition cost) from Soso of $28.2 million.

Martinville Field. We initiated our first injections of CO_2 in Martinville Field during the first quarter of 2006 in both the Rodessa and Mooringsport formations. As is the case with most of the East Mississippi fields, Martinville produces from multiple reservoirs. Unlike the majority of our other planned CO_2 projects, Martinville does not contain a single large reservoir to CO_2 flood, but rather several smaller reservoirs. We completed construction of the CO_2 facilities and completed the development of the Mooringsport formation during 2006. During 2008, an additional producing well was drilled to expand the development of the Rodessa sand. A Lower Hosston "huff and puff" project was also initiated. The Lower Hosston project consists of injecting a predetermined volume of CO_2 into the reservoir, allowing the CO_2 time to disperse and contact oil, then flowing the well back and producing the oil that contacted the CO_2. We experienced operational difficulties in producing the first cycle of this "huff and puff" test during 2009 and moved uphole to another Hosston interval. Early in 2010, we started the production cycle from this interval and its preliminary results are promising.

During the fourth quarter of 2009, production at Martinville averaged 724 Bbls/d, almost all of which is from the Mooringsport. To date, we have booked additional proved reserves in the Mooringsport, Rodessa IX and a small amount in the Wash-Fred reservoirs. There are several additional Rodessa reservoirs that will be developed following completion of the CO_2 flood in the Rodessa IX. From inception through December 31, 2009, we had not yet recovered our costs in this field with net negative cash flow (revenue less operating expenses and capital expenditures, including the acquisition cost) from Martinville of $2.6 million.

The Martinville Field Wash Fred 8500' reservoir development continues to evolve. The Wash Fred formation contains a low oil gravity (thick oil), 15o API, which will not develop miscibility with CO_2 at reservoir conditions. Denbury has several fields with similar low gravity oils, which like the Wash Fred 8500' have had lower recoveries due to the low oil gravities and strong water drives, which do not sweep the oil efficiently. We have experimented with this reservoir since 2006 but have not had much success until recently, when an offset producing well began to produce oil during 2009.

We plan on reactivating one more well to production in 2010, and continue to increase CO_2 injection into this reservoir over time. The ability to produce and process this heavy crude has been difficult, but if we can economically and satisfactorily resolve these issues, this field could provide the impetus to look at other heavy oil reservoirs and fields that we have not previously considered.

Heidelberg Field. During 2009, we added Heidelberg Field as our twelfth producing EOR field. Construction of the CO_2 facility, connecting pipeline and well work commenced during 2008, with our, first CO_2 injections beginning in December 2008. During 2009, we added eight new injection patterns and expanded the central processing facility. Our first tertiary oil production response occurred during May 2009. The first four stages of Heidelberg's CO_2 flood are in the West Heidelberg Unit (WHEOUP) Eutaw formation, the same formation we are CO_2 flooding at Eucutta Field. Although similar in many respects, the Eutaw reservoir at Heidelberg contains two to three times the potential oil reserves as the Eutaw formation at Eucutta Field. During the fourth quarter of 2009, production at Heidelberg Field averaged 1,506 Bbls/d. During 2010, we plan to complete the development of the CO_2 flood in WHEOUP at an estimated cost of approximately $40 million. Development of the East Heidelberg Units will begin in 2011.

From inception through December 31, 2009, we had not yet recovered our cost in this field, with net negative cash flow (revenue less operating expenses and capital expenditures, including the acquisition cost) from Heidelberg of $60.8 million.

Phase 3 Field

Tinsley Field. Tinsley Field was acquired in January 2006 and is the largest oil field in the state of Mississippi. 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. We initiated limited CO_2 injections in January 2007 through a previously existing 8" pipeline, but replaced this line in 2008 with the 24" Delta Pipeline. We had our first tertiary oil production commencing in April 2008. During 2009, we expanded the central processing facilities and completed Phase 3, which consisted of 31 producing wells and six injection well conversions. A similar capital investment level of approximately $44 million is scheduled during 2010, as we continue to expand into Phase 4. During the fourth quarter of 2009, the average oil production was 3,942 Bbls/d. Tinsley Field produced an additional 351 Bbls/d from non-CO_2 operations during the fourth quarter of 2009.

From inception through December 31, 2009, we had not yet recovered our costs in this field, with net negative cash flow (revenue less operating expenses and capital expenditures, including the acquisition cost) from Tinsley of $218.8 million.

Phase 4 Field

Cranfield Field. During 2008, we began development of Cranfield with the drilling or re-entry of 11 CO_2 injectors and 11 producers and reconditioned the natural gas pipeline that we purchased, converting it to CO_2 service. We commenced injections into the Lower Tuscaloosa reservoir in the third quarter of 2008 and had our first tertiary oil production in the first quarter of 2009. We continued to expand the flood during 2009 with the drilling of an additional 2 producers and 2 CO_2 injection wells along with two re-entries of existing wells. During the fourth quarter of 2009, production at Cranfield Field averaged 728 Bbls/d. During 2010 we plan to spend approximately $35 million for the drilling of an additional five producers and nine CO_2 injection wells, along with seven re-entries of existing wells. We are participating with the Bureau of Economic Geology (BEG) at the University of Texas as they study CO_2 injection and sequestration at Cranfield, to better define and understand the movement of CO_2 through the Lower Tuscaloosa reservoir. The results of this study could lead to a greater recovery of the oil in the reservoir.

From inception through December 31, 2009, we had not yet recovered our investment in this field, with net negative cash flow (revenue less operating expenses and capital expenditures, including the acquisition cost) from Cranfield of $86.5 million.

Our Tertiary Oil Fields Without Proved Tertiary Reserves

Conroe Field. On December 18, 2009, we purchased a 95% interest in the Conroe Field, a potentially significant tertiary flood north of Houston, Texas, for approximately $254.2 million in cash and 11,620,000 shares of Denbury common stock. We have internally estimated that the Conroe Field interests have significant estimated net reserve potential from CO_2 tertiary recovery, the largest EOR potential of our Gulf Coast oil fields. The acquired Conroe Field interests have estimated proved conventional reserves of approximately 18.5 MMBbls at December 31, 2009, nearly all of which are proved developed. The Conroe Field assets are currently producing around 2,500 BOE/d net to our acquired interest. We will need to build a pipeline to transport CO_2 to this field, preliminarily estimated to cover 80 miles, as an extension of our Green pipeline. Based on our preliminary estimates, Denbury will spend an additional $750 million to $1.0 billion, including the cost of the CO_2 pipeline, to develop the Conroe Field as a tertiary flood. The development of this tertiary flood is not expected to begin for four or five years.

Delhi Field. During May 2006, we purchased the Delhi Holt-Bryant Unit ("Delhi") in Northern Louisiana for $50 million, plus a 25% reversionary interest to the seller after we achieve $200 million in net operating income. We began well work development in 2008 and drilled or recompleted additional wells in 2009 and built a processing facility. We began delivering CO_2 to the field in the fourth quarter of 2009 via the recently completed Delta Pipeline (Tinsley to Delhi). Based on early indications, the first enhanced oil production response is anticipated mid-2010. Our 2010 capital plans for the Delhi Field include the drilling of 26 wells and the workover or re-entry of an additional 30 wells. As of December 31, 2009, there was no significant oil production nor proved tertiary oil reserves at Delhi Field.

Hastings Field. During November 2006, we entered into an agreement with a subsidiary of Venoco, Inc. that gave us an option to purchase their interest in Hastings Field, a strategically significant potential tertiary flood candidate located near Houston, Texas. We exercised the purchase option prior to September 2008, and closed the $201 million acquisition during February 2009. As consideration for the option agreement, we made total payments of $50 million.

The purchase price of $201 million included approximately $4.9 million for certain surface land, oilfield equipment and other related assets. Under the terms of the agreement, Venoco, Inc., the seller, retained a 2% override and reversionary interest of approximately 25% following payout, as defined in the option agreement. During the fourth quarter of 2009, production from Hastings Field averaged 1,983 BOE/d, with conventional proved reserves at December 31, 2009 of approximately 8.9 MMBOE. We plan to commence flooding the field with CO_2 beginning in late 2010 or early 2011, after completion of our Green Pipeline currently under construction.

Based on preliminary engineering data, the West Hastings Unit (the most likely area to be initially developed as a tertiary flood) has significant net reserve potential from CO_2 tertiary floods, the second largest reserve potential of any other single field in our inventory. We started construction of the Green Pipeline during November 2008 to transport CO_2 to this field (see "CO_2 Pipelines" above). Based on our latest estimates, it will cost between $400 million and $600 million to develop the West Hastings Unit as a tertiary flood, excluding the cost of the Green Pipeline.

Oyster Bayou, Fig Ridge and Gillock Fields. During 2007, we acquired an interest in three fields in Southeast Texas with significant tertiary potential. The Oyster Bayou and Fig Ridge Fields are located in close proximity to each other and are located on or close to the Green Pipeline. We acquired the majority interest in Oyster Bayou Field and a relatively small interest in Fig Ridge Field. We initiated unitization hearings at Oyster Bayou Field during 2009. Because of current lack of majority interest at Fig Ridge Field, we will need the cooperation of other operators and lease owners to form the necessary unit. We plan to commence flooding the Oyster-Bayou Field with CO_2 beginning in mid-2010.

Our acquisitions in Gillock Field include an acquisition of almost all of the South Gillock Unit, the Southeast Gillock unit and the acquisition of a key lease in the Gillock Field. The Gillock acquisitions are located near the proposed Green Pipeline and Hastings Field. Denbury continues to evaluate potential acquisition candidates in Southeast Texas and in Louisiana in proximity to our Green Pipeline and near our pipelines in Mississippi.

Overall Tertiary Economics to Date. Through December 31, 2009, we have invested a total of $1.8 billion on tertiary oil fields (including the allocated acquisition costs and amounts assigned to Goodwill), and received $1.6 billion in net operating income (revenue less operating expenses), or net unrecovered cash flow of $225.7 million, the deficit primarily due to the significant funds expended on acquisitions during 2009. Of our total spending, approximately $487.4 million was invested to date on fields that had little or no proved reserves at December 31, 2009 (i.e., significant incremental proved reserves are anticipated in future years). These amounts do not include the capital costs or related depreciation and amortization of our CO_2 producing properties at Jackson Dome, which had an unrecovered net cash flow of $1.4 billion as of December 31, 2009, including $1.1 billion associated with CO_2 pipelines. At year-end 2009, the proved oil reserves in our tertiary recovery oil fields had a PV-10 Value of approximately $2.3 billion, using 12-month first-day-of-the-month unweighted average NYMEX pricing of $61.18 per barrel. In addition, there are significant probable and possible reserves at several other fields for which tertiary operations are under way or planned.

Potential Tertiary Oil Properties from Proposed Acquisition of Encore. The proposed acquisition of Encore (see "Item 1. Business – Definitive Merger Agreement to Acquire Encore Acquisition Company") includes Encore's legacy oil fields located in Montana, North Dakota and Wyoming which will allow us to expand our EOR platform to this region. At the time that the merger was announced, these fields nearly doubled our total potential oil reserves recoverable through EOR. These legacy oil assets are estimated to have over 6 billion barrels of original oil in place, assets that are distinguished by their long reserve life and low decline rates and that have significant potential for recovery of crude oil through CO_2 EOR. Denbury expects its significant expertise in EOR in the Gulf Coast to be directly applicable to Encore's Rocky Mountain oilfield assets.

East Mississippi Fields without Proved Tertiary Oil Reserves

We have been active in East Mississippi since Denbury was founded in 1990 and are by far the largest oil producer in the basin and the state. Conventional or non-tertiary production during the fourth quarter of 2009 averaged approximately 8,914 BOE/d from this area (20% of our Company total), and we had proved reserves of 36.1 MMBOE as of December 31, 2009 (17% of our Company total). Since we have generally owned these Eastern Mississippi properties longer than properties in our other regions, they tend to be more fully developed, and although most are targeted for tertiary operations in the future, only four currently have tertiary operations (Soso, Martinville, Eucutta and Heidelberg Fields). Production from our conventional and secondary recovery operations in our East Mississippi fields has been gradually depleting, as expected, over the last three years, averaging 12,479 BOE/d in 2007, 11,897 BOE/d during 2008 and 9,937 BOE/d during 2009. During 2009, we invested very little capital in the non-tertiary assets in these reserves.

Heidelberg Field. The largest field in the region and one of our largest fields corporately is Heidelberg Field, which for the fourth quarter of 2009 produced an average of 5,411 BOE/d of conventional or non-tertiary production. Heidelberg Field was acquired from Chevron in December 1997. The field is a large salt-cored anticline that is divided into western and eastern segments due to subsequent faulting. Most of the past and current production comes from the Eutaw, Selma Chalk and Christmas sands at depths from 3,500′ to 5,000′.

The majority of the conventional oil production at Heidelberg is from waterflood units that produce from the Eutaw formation (at approximately 4,400′). Most of our recent development at Heidelberg, other than our tertiary operations, has been in the Selma Chalk, a natural gas reservoir at around 3,700′, which subsequent to the sale of our Barnett Shale assets during 2009, is our only significant remaining natural gas property (prior to the pending Encore acquisition). We have steadily developed the Selma Chalk since 2001, increasing the natural gas production at Heidelberg to a peak quarterly average of 19.4 MMcf/d in the fourth quarter of 2008. During late 2006 and early 2007, we drilled our first horizontal wells in West Heidelberg Field where vertical wells were generally uneconomic. The horizontal wells have performed well and thus we expect to be able to expand our Selma Chalk development throughout West Heidelberg Field. We severely curtailed capital expenditures on non-tertiary operations at Heidelberg in 2009 as a result of lower commodity prices and a desire to allocate our capital resources to our core tertiary operations. Our current plans include drilling one additional well in the Selma Chalk during 2010.

FIELD SUMMARIES — PRODUCTION AND PROVED RESERVES

Denbury operates in five primary areas: Eastern Mississippi, Western Mississippi, Texas, Alabama and Louisiana. Our 19 largest fields (listed below) constitute approximately 97% of our total proved reserves on a BOE basis, and 96% of our total proved reserves on a PV-10 Value basis. Within these 19 fields, we own a weighted average 95% working interest and operate all of these fields. The concentration of value in a relatively small number of fields allows us to benefit substantially from any operating cost reductions or production enhancements we achieve, and allows us to effectively manage the properties from our four primary field offices located in Laurel, Mississippi; Jackson, Mississippi; Little Creek, Mississippi; and Alvin, Texas.

	Proved Reserves as of December 31, 2009[1]					2009 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)	Avg NRI
Tertiary Oil Fields								
Tinsley[3]	33,910	—	33,910	16.3%	$ 583,973	3,328	—	79.9%
Heidelberg	25,433	—	25,433	12.3%	410,680	651	—	85.6%
Brookhaven	15,972	—	15,972	7.7%	329,918	3,416	—	81.3%
McComb Area	12,518	—	12,518	6.0%	197,465	2,391	—	79.0%
Cranfield	10,778	—	10,778	5.2%	189,935	448	—	77.9%
Eucutta	10,187	—	10,187	4.9%	166,240	3,985	—	83.5%
Mallalieu	9,984	—	9,984	4.8%	181,118	4,107	—	79.0%
Soso	8,028	—	8,028	3.9%	119,425	2,834	—	77.3%
Lockhart Crossing	3,705	—	3,705	1.8%	57,381	804	—	58.2%
Little Creek & Lazy Creek	2,999	—	2,999	1.4%	42,149	1,502	—	83.2%
Martinville	1,005	—	1,005	0.5%	8,193	877	—	77.6%
Total Tertiary Oil Fields	134,519	—	134,519	64.8%	2,286,477	24,343	—	79.3%
Mississippi								
Heidelberg	14,079	54,964	23,240	11.2%	203,203	3,605	14,768	75.7%
Sharon	16	24,512	4,101	2.0%	27,878	11	7,848	72.7%
Eucutta	1,308	—	1,308	0.6%	24,546	309	—	41.6%
Summerland	1,255	—	1,255	0.6%	14,780	316	—	74.4%
S. Cypress Creek	910	61	920	0.4%	15,454	150	10	83.1%
Other Mississippi	4,934	1,882	5,248	2.5%	85,733	1,591	1,108	16.8%
Total Mississippi	22,502	81,419	36,072	17.3%	371,594	5,982	23,734	41.1%
Texas								
Conroe	18,132	2,319	18,519	8.9%	210,163	117	123	80.4%
Hastings	8,862	—	8,862	4.3%	119,336	1,954	9	79.1%
Other Texas	224	746	348	0.2%	3,547	3,051	42,057	67.6%
Total Texas	27,218	3,065	27,729	13.4%	333,046	5,122	42,189	65.8%
Alabama								
Citronelle	8,074	—	8,074	3.9%	64,175	1,108	—	63.4%
Alabama and other	115	87	130	0.1%	2,115	5	52	2.1%
Total Alabama and Other	8,189	87	8,204	4.0%	66,290	1,113	52	52.0%
Louisiana								
Onshore Louisiana	451	3,404	1,018	0.5%	18,052	391	2,111	29.3%
Company Total	192,879	87,975	207,542	100%	$ 3,075,459	36,951	68,086	64.6%

(1) The reserves were prepared in accordance with the guidelines of FASC topic 932 "Extractive Industries – Oil and Gas" using the average first-day-of-the-month prices for each month during 2009 which for NYMEX oil was a price of $61.18 per barrel adjusted to prices received by field and for natural gas was a Henry Hub cash price of $3.87 per MMBtu, also adjusted to prices received by field.

(2) PV-10 Value is a non-GAAP measure and is different from the Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") in that PV-10 Value is a pre-tax number and the Standardized Measure is an after-tax number. The information used to calculate PV-10 Value is derived directly from data determined in accordance with FASC topic 932. The Standardized Measure was $2.5 billion at December 31, 2009. A comparison of PV-10 to the Standardized Measure is included in the table on page 24 as well as further information regarding our use of this non-GAAP measure.

(3) Tinsley Field, which had initial tertiary oil production response from CO_2 injections during the first quarter of 2008, had an average sales price per unit of oil of $63.09 per barrel in 2009 and $96.36 per barrel in 2008. Tinsley Field average production cost (excluding ad valorem and severance taxes) was $18.93 per barrel in 2009 and $33.01 per barrel in 2008.

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 Denbury's 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 gas production.

Oil and Gas Acreage

The following table sets forth Denbury's acreage position at December 31, 2009:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Mississippi	153,691	110,200	248,814	33,371	402,505	143,571
Louisiana	36,029	34,322	4,570	3,891	40,599	38,213
Texas	41,227	38,853	5,964	2,553	47,191	41,406
Alabama	19,893	15,397	69,206	12,351	89,099	27,748
Other	6,853	816	16,543	3,036	23,396	3,852
Total	257,693	199,588	345,097	55,202	602,790	254,790

Denbury's net undeveloped acreage that is subject to expiration over the next three years, if not renewed, is approximately 10% in 2010, 54% in 2011 and 6% in 2012.

Productive Wells

The following table sets forth our gross and net productive oil and natural gas wells at December 31, 2009:

	Producing Oil Wells		Producing Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Operated Wells:						
Mississippi	689	664.4	216	197.8	905	862.2
Louisiana	34	26.3	9	9.0	43	35.3
Texas	248	231.2	38	34.5	286	265.7
Alabama	170	135.9	5	3.1	175	139.0
Total	1,141	1,057.8	268	244.4	1,409	1,302.2
Non-Operated Wells:						
Mississippi	36	2.2	230	3.8	266	6.0
Louisiana	—	—	1	—	1	—
Texas	6	6.0	—	—	6	6.0
Alabama	—	—	3	0.7	3	0.7
Other	32	0.6	—	—	32	0.6
Total	74	8.8	234	4.5	308	13.3
Total Wells:						
Mississippi	725	666.6	446	201.6	1,171	868.2
Louisiana	34	26.3	10	9.0	44	35.3
Texas	254	237.2	38	34.5	292	271.7
Alabama	170	135.9	8	3.8	178	139.7
Other	32	0.6	—	—	32	0.6
Total	1,215	1,066.6	502	248.9	1,717	1,315.5

Drilling Activity

The following table sets forth the results of our drilling activities over the last three years:

	Year Ended December 31,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:(1)						
Productive(2)	1	1.0	—	—	9	6.2
Non-productive(3)	—	—	1	1.0	4	3.4
Development Wells:(1)						
Productive(2)	23	16.6	102	98.3	101	96.8
Non-productive(3)(4)	—	—	1	0.7	—	—
Total	24	17.6	104	100.0	114	106.4

(1) An exploratory well is a well drilled either in search of a new, as yet undiscovered, oil and natural gas reservoir or to greatly extend the known limits of a previously discovered reservoir. A development well is a well drilled within the presently proved productive area of an oil or natural gas reservoir, as indicated by reasonable interpretation of available data, with the objective of completing in that reservoir.

(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 nonproductive well is an exploratory or development well that is not a producing well.

(4) During 2009, 2008 and 2007 an additional 20, 33 and 23, wells, respectively, were drilled for water or CO_2 injection purposes.

PRODUCTION AND UNIT PRICES

Information regarding average production rates, unit sale prices and unit costs per BOE are set forth under "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. During acquisitions, title reviews are performed on all properties; however, formal title opinions are obtained on only the higher value properties. We believe that we have good title to our oil and natural gas properties, some of which are subject to minor encumbrances, easements and restrictions.

GEOGRAPHIC SEGMENTS

All of our operations are in the United States.

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 year ended December 31, 2009, two purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company LLC (52%) and Hunt Crude Oil Supply Co. (21%). For the year ended December 31, 2008, we had three significant purchasers that each accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company LLC (49%), Hunt Crude Oil Supply Co. (20%) and Crosstex Energy Field Services Inc. (14%). For the year ended December 31, 2007, three purchasers each accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company LLC (43%), Hunt Crude Oil Supply Co. (19%) and Crosstex Energy Field Services Inc. (16%).

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 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 is primarily from developed fields close to major pipelines or refineries and established infrastructure. As a result, we have not experienced any difficulty to date in finding a market for all of our production as it becomes available or in transporting our production to those markets; however, there is no assurance that we will always be able to market all of our production or obtain favorable prices.

Oil Marketing

The quality of our crude oil varies by area, thereby impacting the corresponding price received. As an example, in Heidelberg Field, one of our larger fields, and our other Eastern Mississippi non-tertiary properties, our oil production is primarily light to medium sour crude and sells at a significant discount to the NYMEX prices. In Western Mississippi, the location of our Phase 1 tertiary operations, our oil production is primarily light sweet crude, which typically sells at near NYMEX prices, or often at a premium. For the year ended December 31, 2009, the discount for our non-tertiary oil production from Heidelberg Field averaged $10.59 per Bbl and for our Eastern Mississippi non-tertiary properties as a whole the discount averaged $9.26 per Bbl relative to NYMEX oil prices. For our Phase 1 tertiary fields in Southwest Mississippi, we averaged a premium of $1.21 per Bbl over NYMEX oil prices during 2009.

Natural Gas Marketing

Virtually all of our natural gas production is close to existing pipelines and consequently we generally have a variety of options to market our natural gas. We sell the majority of our natural gas on one-year contracts with prices fluctuating month-to-month based on published pipeline indices with slight premiums or discounts to the index. We receive near NYMEX or Henry Hub prices for most of our natural gas sales in Mississippi. For the year ended December 31, 2009, we averaged $0.14 per Mcf below NYMEX prices for our Mississippi natural gas production. However, in the Texas Gulf Coast region, due primarily to its location, the price we received averaged $0.01 per Mcf above NYMEX prices.

COMPETITION AND MARKETS

We face competition from other oil and natural gas companies in all aspects of our business, including acquisition of producing properties and oil and gas leases, marketing of oil and 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 standards established for minimum projected return on investment. 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 by alternative fuel sources, including heating oil and other fossil fuels. Because of the nature of our core assets (our tertiary operations) and our ownership of a relatively uncommon significant natural source of carbon dioxide, we believe that we are effective in competing in the market.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. There have also been shortages of drilling rigs and other equipment, as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. We cannot be certain when we will experience these issues, and these types of shortages or price increases could significantly decrease our profit margin, cash flow and operating results or restrict our ability to drill those wells and conduct those operations that we currently have planned and budgeted.

FEDERAL AND STATE REGULATIONS

Numerous federal and state laws and regulations govern the oil and gas industry. These laws and regulations are often changed in response to changes in the 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 section describes some specific laws and regulations that may affect us. We cannot predict the impact of these or future legislative or regulatory initiatives.

Management believes that we are in substantial compliance with all laws and regulations applicable to our operations and that continued compliance with existing requirements will not have a material adverse impact on us. The future annual capital cost of complying with the regulations applicable to our operations is uncertain and will be governed by several factors, including future changes to regulatory requirements. However, management does not currently anticipate that future compliance will have a materially adverse effect on our consolidated financial position or results of 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 disposal of fluids used in connection with operations. Our operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling, spacing or proration units and the density of wells that may be drilled in those units, and the unitization or pooling of oil and gas properties. In addition, state conservation laws which establish maximum rates of production from oil and gas wells generally prohibit the venting or flaring of gas and impose certain requirements regarding the ratability of production. The effect of these regulations may limit the amount of oil and 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. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. The ultimate impact of the complex rules and regulations issued by FERC cannot be predicted. Some of FERC's proposals may, however, 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. Historically, the natural gas industry has been heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by FERC, Congress and the states will continue indefinitely into the future.

Federal Energy and Climate Change Legislation

In October 2008, as part of the Emergency Economic Stabilization Act, Congress included a new tax credit for carbon capture and sequestration, including that achieved through enhanced oil recovery, as further modified by the American Recovery and Reinvestment Act of 2009, passed in February 2009. In future periods Congress may decide to revisit legislation introduced in prior sessions to repeal existing incentives or impose new taxes on the exploration nd production of oil, gas and other minerals, and/or create new incentives for alternative energy sources. Congress may also consider legislation to reduce emissions of carbon dioxide or other gases. If enacted, such legislation could impose a tax or other economic penalty on the production of fossil fuels that, when used, ultimately release CO_2, and could reduce the demand for and uses of oil, gas and other minerals and/or increase the costs incurred by the Company in its exploration and production activities. At the same time, legislation to reduce the emissions of carbon dioxide or other 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 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 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, Minerals Management Service ("MMS") and other agencies.

Environmental Regulations

Public interest in the protection of the environment has increased dramatically in recent years. Our oil and natural gas production and saltwater disposal operations, and our processing, handling and disposal of hazardous materials such as hydrocarbons and naturally occurring radioactive materials are subject to stringent regulation. We could incur significant costs, including cleanup costs resulting from a release of hazardous material, third-party claims for property damage and personal injuries, fines and sanctions, as a result of any violations or liabilities under environmental or other laws. Changes in or more stringent enforcement of environmental laws could also result in additional operating costs and capital expenditures.

Various federal, state and local laws regulating the discharge of materials into the environment, or otherwise relating to the protection of the environment, directly impact oil and gas exploration, development and production operations, and consequently may impact the Company's operations and costs. These regulations include, among others, (i) regulations by the EPA and various state agencies regarding approved methods of disposal for certain hazardous and nonhazardous wastes; (ii) the Comprehensive Environmental Response, Compensation, and Liability Act, Federal Resource Conservation and Recovery Act and analogous state laws that regulate the removal or remediation of previously disposed wastes (including wastes disposed of or released by prior owners or operators), property contamination (including groundwater contamination), and remedial plugging operations to prevent future contamination; (iii) the Clean Air Act and comparable state and local requirements, which may result in the gradual imposition of certain pollution control requirements with respect to air emissions from the operations of the Company or could result in the imposition of economic penalties on the production of fossil fuels that, when used, ultimately release CO_2; (iv) the Oil Pollution Act of 1990, which contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States; (v) the Resource Conservation and Recovery Act, which is the principal federal statute governing the treatment, storage and disposal of hazardous wastes; and (vi) state regulations and statutes governing the handling, treatment, storage and disposal of naturally occurring radioactive material ("NORM").

Management believes that we are in substantial compliance with applicable environmental laws and regulations. Management does not currently anticipate that future compliance will have a materially adverse effect on our consolidated financial position, results of operations or cash flows.

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

Internal Controls Over Reserve Estimates

We engage an independent petroleum engineering consulting firm to prepare our reserve estimates and rely on their expertise to ensure that our reserve estimates are prepared in compliance with SEC guidelines and with generally accepted petroleum engineering principles. The person responsible for the preparation of the reserve report is a Senior Vice President at this consulting firm; he is a Registered Professional Engineer in the State of Texas; he received a Bachelor of Science degree in Petroleum Engineering at Texas A&M University in 1974; and he has in excess of thirty-five years of experience in oil and gas reservoir studies and evaluations. Denbury's Vice President – Business Development is primarily responsible for overseeing the independent petroleum engineering firm during the process. Our Vice President – Business Development has a Bachelor of Science degree in Petroleum Engineering and over 20 years of industry experience working with petroleum reserve estimates. The Company's internal reserve engineering team consists of qualified petroleum engineers who both provide data to the independent petroleum engineer and prepare interim reserve estimates. The internal reserve team reports directly to our Vice President – Business Development. In addition, the Company's Board of Directors' Reserves Committee, on behalf of the Board of Directors, oversees the qualifications, independence, performance and hiring of the Company's independent petroleum engineering firm and reviews the final report and subsequent reporting of the Company's oil and natural gas reserves. The Chairman of the Reserves Committee is a Chartered Engineer of Great Britain and received his Bachelor of Science degree in Chemical Engineering from the University of London in 1963.

Reserves Estimates

DeGolyer and MacNaughton, independent petroleum engineers located in Dallas, Texas, prepared estimates of our net proved oil and natural gas reserves as of December 31, 2009, 2008 and 2007. See the summary of DeGolyer and MacNaughton's report as of December 31, 2009 included as an exhibit to this Form 10-K. Estimates of reserves as of year-end 2009 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 ended December 31, 2009, in accordance with revised guidelines of the SEC, first applicable to reserves estimates prepared as of year-end 2009. Estimates of reserves as of year-end 2007 and 2008 were prepared using constant prices and costs in accordance with previous guidelines of the SEC, based on hydrocarbon prices received on a field-by-field basis as of December 31st of each year. 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 2009, we provided oil and gas reserve estimates for 2008 to the United States Energy Information Agency, which was substantially the same as the reserve estimates included in our Form 10-K for the year ended December 31, 2008.

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.

Proved undeveloped reserves associated with our CO_2 tertiary operations and our Heidelberg waterfloods account for virtually all of our proved undeveloped oil reserves. We consider these reserves to be lower risk than other proved undeveloped reserves that require drilling at locations offsetting existing production because all of these proved undeveloped reserves are associated with secondary recovery or tertiary recovery operations in fields and reservoirs that historically produced substantial volumes of oil under primary production. The main reason these reserves are classified as undeveloped is because they require significant additional capital associated with drilling/re-entering wells or additional facilities in order to produce the reserves and/or are waiting for a production response to the water or CO_2 injections. Virtually all of our proved undeveloped natural gas reserves are located in our Selma Chalk play at Heidelberg and Sharon Fields at December 31, 2009. Our current plans include drilling five additional wells in the Selma Chalk play during 2010, one at Heidelberg and four at Sharon. Our proved undeveloped reserves decreased from December 31, 2008 to December 31, 2009 primarily due to the sale of our Barnett Shale natural gas assets during 2009.

	December 31, 2009	2008	2007
Estimated Proved Reserves:			
Oil (MBbls)	192,879	179,126	134,978
Natural gas (MMcf)	87,975	427,955	358,608
Oil equivalent (MBOE)	207,542	250,452	194,746
Reserve Volumes:			
Proved developed producing:			
Oil (MBbls)	93,833	73,347	73,457
Natural gas (MMcf)	67,952	270,824	216,455
Oil equivalent (MBOE)	105,158	118,484	109,533
Proved developed non-producing:			
Oil (MBbls)	22,359	23,399	23,549
Natural gas (MMcf)	1,561	27,290	9,816
Oil equivalent (MBOE)	22,619	27,947	25,185
Proved undeveloped:(1)			
Oil (MBbls)	76,687	82,380	37,972
Natural gas (MMcf)	18,462	129,841	132,337
Oil equivalent (MBOE)	79,764	104,020	60,028
Percentage of Total MBOE:			
Proved producing	51%	47%	56%
Proved non-producing	11%	11%	13%
Proved undeveloped	38%	42%	31%
Representative Oil and Natural Gas Prices:(2)			
Oil – NYMEX	$ 61.18	$ 44.60	$ 95.98
Natural gas – Henry Hub	3.87	5.71	6.80
Present Values (thousands):(3)			
Discounted estimated future net cash flow before income taxes ("PV-10 Value")(4)	$3,075,459	$1,926,855	$5,385,123
Standardized measure of discounted estimated future net cash flow after income taxes	2,457,385	1,415,498	3,539,617

(1) Certain of our proved undeveloped reserves related to our tertiary properties have a development period that extends beyond 5 years. In each of these tertiary properties, the majority of the spending on facilities has been completed and a response to CO_2 injections has occurred. Therefore, these tertiary oil reserves have been included as proved undeveloped, and will be further classified as proved developed as the remaining field development is completed. In addition, at December 31, 2009, a total of approximately 3.6 MMBOE of tertiary reserves at Brookhaven Field and McComb Field have been held as proved undeveloped for a period greater than five years. It is expected that these reserves will become proved developed reserves during the next several years as the remaining tertiary development at these two fields is completed.

(2) The reference prices for 2009 were based on the average first-day-of-the-month prices for each month during 2009. The reference prices for 2008 and 2007 were based on respective year-end prices. For all the periods presented, these representative prices were adjusted for differentials by field to arrive at the appropriate net price Denbury receives.

(3) Determined based on the average first day of the month prices for each month during 2009 and year-end unescalated prices for 2008 and 2007, in all cases adjusted to prices received by field in accordance with the guidelines of 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 $618,074 at December 31, 2009, $511,357 at December 31, 2008 and $1,845,506 at December 31, 2007. 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 Note 16 to our 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 flow is difficult to do with any certainty." See also Note 16, "Supplemental Oil and Natural Gas Disclosures," to the Consolidated Financial Statements.

ITEM 1A. RISK FACTORS

RISKS RELATED TO OUR BUSINESS

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

General

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 in such indebtedness, including covenants in our senior secured credit facilities, we would be in default under our debt instruments. This default would permit the holders of such indebtedness to accelerate the maturity of such indebtedness and could cause defaults under other indebtedness or result 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 to financial, business and other factors, including factors beyond our control.

Denbury Stand-Alone

As of February 15, 2010, we had outstanding $525 million (principal amount) of 7.5% subordinated notes, $426.4 million (principal amount) of 9.75% Senior Subordinated Notes, $1.0 billion of 8.25% Senior Subordinated Notes (held in escrow pending completion of the Merger and tender of Encore notes), and $125 million of bank debt. At that time, we had approximately $625 million available on our bank credit line. We currently have a bank borrowing base of $900 million, with a commitment amount of $750 million. The borrowing base represents the amount that can be borrowed from a credit standpoint, while the commitment amount is the amount the banks have committed to fund pursuant to the terms of the credit agreement. The next semi-annual redetermination of the borrowing base for our bank credit facility will be on April 1, 2010, assuming the Merger is not completed. 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 of six months.

We may incur additional indebtedness in the future under our bank credit facility (which we anticipate being a $1.6 billion facility if the Encore Merger closes), in connection with our acquisition, development, exploitation and exploration of oil and natural gas producing properties. Our projected 2010 capital expenditures, excluding acquisitions and capital expenditures related to the Encore acquisition, are expected to be between $150 million and $250 million higher than our projected 2010 cash flow from operations. 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 other purposes;
- as a result of the discretionary nature of the setting of our bank borrowing base and its being highly dependent on current commodity prices, if commodity prices were to substantially decrease, our banks could reduce our borrowing base so that we could not borrow additional funds or to a level below our outstanding debt that would require us to repay any deficit (between the borrowing base and the outstanding bank debt) over a four month period;
- our business may not generate sufficient cash flow from operations to enable us to continue to meet our obligations under our indebtedness;
- 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 interest rates, because certain of our borrowings are at variable rates of interest;
- our vulnerability to general adverse economic and industry conditions may be greater as a result of our level of indebtedness, and increases in interest rates thereon, potentially restricting us from making acquisitions, introducing new technologies or exploiting business opportunities;

- our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments may be limited by the covenants contained in the agreements governing our outstanding indebtedness limit; and
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry. Our failure to comply with such covenants could result in an event of default under such debt instruments which, if not cured or waived, could have a material adverse effect on us.

Combined Company – Post Denbury/Encore Merger

Denbury will be more leveraged after the merger than it has been historically. Upon closing of the merger and the revolving credit facility contemplated by the merger agreement, we will have $1.975 billion of revolving credit facilities. Borrowings under the newly committed credit facility combined with Denbury's existing debt, including the $1 billion of 8.25% Senior Subordinated Notes due 2020 issued in February 2010, are expected to be approximately $3.6 billion of total pro forma combined long-term debt after the completion of the merger. This level of indebtedness could result in Denbury having difficulty accessing capital markets or raising capital on favorable terms and Denbury's financial results could be negatively affected by its inability to raise capital or because of the cost of such capital.

Our substantial debt following the merger and the related financing could have important consequences for us. For example, it could:

- increase our vulnerability to general adverse economic and industry conditions;
- limit our ability to fund future working capital and capital expenditures, to engage in future acquisitions or development activities, or to otherwise realize the value of our assets and opportunities fully because of the need to dedicate a substantial portion of our cash flow from operations to payments on our debt or to comply with any restrictive terms of our debt;
- limit our flexibility in planning for, or reacting to, changes in the industry in which we operate; or
- place us at a competitive disadvantage as compared to our competitors that have less debt.

Realization of any of these factors could adversely affect our financial condition. In addition, although we and Encore both have hedges in place for 2010 and 2011, these hedges have varying floors and ceilings and will only partially protect the combined company's cash flow. A decline in commodity prices may require that we reduce our planned capital expenditures, which may have a corresponding negative effect on our anticipated production growth.

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 carbon dioxide. Our ability to produce this oil would be hindered if our supply of carbon dioxide 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. Additionally, the production of crude oil from our planned expansion of tertiary operations into the Rocky Mountain region depends on having access to sufficient amounts of CO_2 in this region. The ability to produce this oil and execute this growth strategy would be hindered if we were unable to obtain necessary CO_2 volumes in the Rocky Mountain region at a cost that is economically viable.

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

Our future financial condition, results of operations and 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, have been particularly volatile over the last 18 months, and may continue to be volatile in the future, especially given current world geopolitical conditions. As a result of the low oil and natural gas prices at

December 31, 2008, we recorded a $226.0 million full cost ceiling test write-down. Subsequent to December 31, 2008, oil and natural gas prices have continued their volatility, with NYMEX oil prices per barrel increasing 78% between year-end 2008 and year-end 2009, and NYMEX natural gas prices per MMBtu decreasing by 3% during the year. Future decreases in commodity prices could require us to record additional full cost ceiling test write-downs. The amount of any future write-down is difficult to predict and will depend upon the oil and natural gas prices at the end of each period, 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. The amount we can borrow or have outstanding under our bank credit facility is subject to semi-annual redeterminations. Oil prices are likely to affect us more than natural gas prices because approximately 93% of our December 31, 2009 proved reserves are oil, prior to closing the pending Encore acquisition, with oil being an even larger percentage of our future potential reserves and projects due to our focus on tertiary operations.

As part of the planned Encore acquisition (see "Item 1 – Business – Definitive Merger Agreement to Acquire Encore Acquisition Company"), we have announced plans to sell a portion of the acquired assets in order to reduce indebtedness incurred to finance the acquisition. If commodity prices were to decrease from price levels that existed at the time we entered into the merger agreement with Encore, such assets may be sold for amounts less than we effectively paid for those assets and possibly for less than we believe are the long-term value of the properties. However, if we choose to reduce the number of assets we sell to avoid asset sales for amounts below our valuations, or if we are unable to obtain a reasonable price for these assets, we would remain more highly leveraged than our historical leverage levels, increasing the risk of adverse financial consequences because of our higher debt levels.

The prices for oil and natural gas are subject to a variety of additional factors that are beyond our control. These factors include:

- the level of 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 ("OPEC") to agree to and maintain oil price and production controls;
- the price of foreign oil and natural gas;
- domestic governmental regulations and taxes;
- the price and availability of alternative fuel sources;
- weather conditions, including hurricanes and tropical storms in and around the Gulf of Mexico;
- market uncertainty;
- political conditions in oil and natural gas producing regions, including the Middle East; 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, oil and natural gas prices 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 and, as a result, could have a material adverse effect upon our financial condition, results of operations, oil and natural gas reserves and the carrying values of our oil and natural gas properties. 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.

Since the end of 1998, oil prices have gone from near historic low prices to historic highs. At the end of 1998, NYMEX oil prices were at historic lows of approximately $12.00 per Bbl, but have generally increased since that time, albeit with fluctuations. For 2008, NYMEX oil prices increases throughout the first six months, averaging approximately $111.03 per Bbl for the first six months of 2008. During the last half of 2008, oil prices declined substantially, ending the year at a

NYMEX price of $44.60 per Bbl. Oil prices again increased through 2009, ending the year at a NYMEX price of $79.36 per barrel. We have oil commodity derivative contracts in place covering approximately 30,000 Bbls/d during 2010 and 25,000 Bbls/d during 2011 (please refer to Note 10 to the Consolidated Financial Statements for further details regarding our commodity derivative contracts). We currently do not have any oil or natural gas commodity derivative contracts in place for subsequent years, and therefore oil prices could decline to a level that makes our tertiary projects uneconomic. If that were to happen, we may decide to suspend future expansion projects, and if prices were to drop below the cash break-even point for an extended period of time, we may decide to shut-in existing production, either of which would have a material adverse effect on our operations. Since operating costs do not decrease as quickly as commodity prices, it is difficult to determine a precise break-even point for our tertiary projects. Based on prior history, we estimate our economic break-even (before corporate overhead and expenses on these projects at current oil prices) occurs at per barrel dollar costs in the range of the mid-thirties, depending on the specific field and area.

The prices we receive for our crude oil do not always correlate with NYMEX prices. Our NYMEX differentials over the last few years have ranged from a low of approximately $1.50 per Bbl to a high of almost $10.00 per Bbl. These variances have been due to various factors and are difficult to forecast or anticipate but have a direct impact on the net oil price we receive.

Natural gas prices have also experienced volatility during the last few years. During 1999, natural gas prices averaged approximately $2.35 per Mcf and, like crude oil prices, have generally trended upward since that time, although with significant fluctuations along the way. NYMEX natural gas prices averaged $7.09 per MMBtu during 2007, $8.89 per MMBtu during 2008, $4.16 per MMBtu during 2009, and ended 2009 at $5.57 per MMBtu.

The recent financial crisis 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 and related turmoil in the global financial system would likely materially affect our liquidity, business and our financial condition. 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, the recent economic situation and current economic condition could lead to reduced demand for oil and gas, or lower prices for oil and gas, or both, which could have a negative impact on our revenues.

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

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

- production is less than expected;
- the counter-party to the derivative contract defaults on its contract obligations; or
- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

In addition, these derivative contracts may limit the benefit we would receive from increases in the prices for oil and natural gas. Information as to these activities is set forth under "Management's Discussion and Analysis of Financial Condition and Results of Operations – Market Risk Management," and in Note 10, "Derivative Instruments and Hedging Activities," to the Consolidated Financial Statements.

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. In addition, certain of our operating activities are subject to numerous risks, including the risk that no commercially productive oil or natural gas reserves will be produced.

During the last few years, we have acquired several fields at a significant cost because we believe that they have significant additional potential through tertiary flooding and we paid a premium price for these properties based on that assumption. In addition, we plan to continue acquiring other old oil fields that we believe are tertiary flood candidates, likely at a premium price. 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.

We face competition from other oil and natural gas companies in all aspects of our business, including acquisition of producing properties and oil and gas leases. Many of our competitors have substantially larger financial and other resources. Other factors that affect our ability to acquire producing properties include available funds, available information about prospective properties and our standards established for minimum projected return on investment.

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

Drilling activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. There can be no assurance that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such wells. Drilling for oil and natural gas 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 seismic data and other technologies used by us do not provide conclusive knowledge, prior to drilling a well, that oil or natural gas is present or may be produced economically. 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 delivering systems and disrupt operations;
- compliance with environmental and other governmental requirements; and
- cost of, or shortages or delays in the availability of, drilling rigs, equipment 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.

We depend on our key personnel.

We believe our continued success depends on the collective abilities and efforts of our senior management. The loss of one or more key personnel could have a material adverse effect on our results of operations. We do not have any employment agreements and do not maintain any key man life insurance policies. Additionally, if we are unable to find, hire and retain needed key personnel in the future, our results of operations could be materially and adversely affected.

Upon consummation of the planned Encore acquisition (see "Item 1 – Business – Definitive Merger Agreement to Acquire Encore Acquisition Company"), we will require more personnel to properly manage the acquired assets. While we hope to retain existing Encore personnel in sufficient numbers to meet these needs, there is no assurance that they will agree to continued employment by a new company or be willing to relocate in order to accommodate such an employment change. In that situation, if we are unable to attract personnel in the open marketplace to meet these needs, the lack of personnel could have a material adverse impact on our operations and financial results. Further, without a proper integration of the two companies, we may not operate at our highest levels of efficiency, which also could materially adversely affect our operations and financial results.

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

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. During periods of high oil and 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.

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, 2009, two purchasers each accounted for more than 10% of our oil and natural gas revenues and in the aggregate, for 73% of these revenues. We would not expect the loss of any single purchaser to have a material adverse effect upon our operations. However, the loss of a large single purchaser could potentially reduce the competition for our oil and natural gas production, which in turn could negatively impact the prices we receive.

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 there from 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.

Quantities of proved reserves are estimated based on economic conditions, including oil and natural gas prices in existence at the date of assessment. Our reserves and future cash flows may be subject to revisions based upon changes in economic conditions, including oil and natural gas prices, as well as due to production results, results of future development, operating and development costs and other factors. Downward revisions of our reserves could have an adverse effect on our financial condition, operating results and cash flows.

The reserve data included in documents incorporated by reference represent only estimates. Estimates of reserves as of year-end 2009 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month period ended December 31, 2009, in accordance with revised guidelines of the Securities and Exchange Commission applicable to reserves estimates as of year-end 2009. Estimates of reserves as of year-end 2007 and 2008 were prepared using constant prices and costs in accordance with previous guidelines of the Securities and Exchange Commission based on hydrocarbon prices received on a field-by-field basis as of December 31st of each year. 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. Actual future prices and costs may be materially higher or lower than the prices and cost as of the date of the estimate.

As of December 31, 2009, approximately 38% of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and may require successful drilling operations. The reserve data assumes that we can and will make these expenditures and conduct these operations successfully, but these assumptions may not be accurate, and this may not occur.

We are subject to complex federal, state and local laws and regulations, including environmental laws, which could adversely affect our business.

Exploration for and development, exploitation, production and sale of oil and natural gas in the United States are subject to extensive federal, state and local laws and regulations, including complex tax laws and environmental laws and regulations. Existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws, regulations or incremental taxes and fees, could harm our business, results of operations and financial condition. We may be required to make large expenditures to comply with environmental and other governmental regulations.

It is possible that new taxes on our industry could be implemented and/or tax benefits could be eliminated or reduced, reducing our profitability and available cash flow. In addition to the short-term negative impact on our financial results, such additional burdens, if enacted, would reduce our funds available for reinvestment and thus ultimately reduce our growth and future oil and natural gas production.

Matters subject to regulation include oil and gas production and saltwater disposal operations and our processing, handling and disposal of hazardous materials, such as hydrocarbons and naturally occurring radioactive materials, discharge permits for drilling operations, spacing of wells, environmental protection and taxation. We could incur significant costs as a result of violations of or liabilities under environmental or other laws, including third-party claims for personal injuries and property damage, reclamation costs, remediation and clean-up costs resulting from oil spills and discharges of hazardous materials, fines and sanctions, and other environmental damages.

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

Numerous legislative and regulatory proposals affecting the oil and gas industry have been proposed or are under consideration by the current federal administration, Congress and various federal agencies. Among these proposals are: (1) climate change legislation introduced in Congress, Environmental Protection Agency regulations, carbon emission "cap-and-trade" regimens, and related proposals, none of which have been have been adopted in final form; (2) proposals contained in the President's budget, along with legislation introduced in Congress, none of which have been enacted by both houses of Congress, to repeal various tax deductions available to oil and gas producers, such as the current tax deduction for intangible drilling and development costs and the current deduction for qualified tertiary injectant expenses, which if eliminated could raise the cost of energy production, reduce energy investment and affect the economics of oil and gas exploration and production activities; and (3) legislation being considered by Congress that would subject the process of hydraulic fracturing to federal regulation under the Safe Drinking Water Act, which could affect Company operations, their effectiveness, and the costs thereof. Generally, any such future laws and regulations could result in increased costs or additional operating restrictions, and could have an effect on demand for oil and gas or prices at which it can be sold. Until any such legislation or regulations are enacted or adopted, it is not possible to gauge their impact on our future operations or our results of operations and financial condition.

RISKS RELATING TO THE MERGER

Business uncertainties and contractual restrictions while the merger is pending may have an adverse effect on Encore or Denbury.

Uncertainty about the effect of the merger on employees, suppliers, partners, regulators and customers may have an adverse effect on Encore. These uncertainties may impair Encore's ability to attract, retain and motivate key personnel until the merger is consummated and could cause suppliers, customers and others that deal with Encore to defer purchases or other decisions concerning Encore or seek to change existing business relationships with Encore.

Failure to complete the merger or delays in completing the merger could negatively affect our stock prices and future business and operations.

If the merger is not completed for any reason, we may be subject to a number of risks, including the following:

- we will not realize the benefits expected from the merger, including a potentially enhanced financial and competitive position;
- the current market price of our common stock may reflect a market assumption that the merger will occur and a failure to complete the merger could result in a negative perception by the stock market generally and a resulting decline in the market price of our common stock;
- certain costs relating to the merger, including certain investment banking, financing, legal and accounting fees and expenses, must be paid even if the merger is not completed, and we may be required to pay substantial fees to the other if the merger agreement is terminated under specified circumstances;
- there may be substantial disruption to our business and distraction of our management and employees from day-to-day operations because matters related to the merger (including integration planning) may require substantial commitments of time and resources, which could otherwise have been devoted to other opportunities that could have been beneficial to us; and
- delays in completing the merger could exacerbate uncertainties concerning the effect of the merger, which may have an adverse effect on the business following the merger and could defer or detract from the realization of the benefits expected to result from the merger.

We are subject to financial risks if we fail to complete the merger under certain circumstances.

If we terminate the merger agreement because Denbury stockholders do not adopt the merger agreement, we will be required to pay Encore $60 million, and in certain cases $120 million. If we terminate the merger agreement because we are unable to obtain the financing necessary to consummate the merger, we will be required to pay to Encore a $300 million termination fee. Further, there is a limited exception that would allow our board of directors to withdraw or change its recommendation to holders of our common stock that they vote in favor of the adoption of the merger agreement. Although our board of directors is permitted to take these actions if it determines in good faith that these actions are likely to be required to comply with its fiduciary duties, doing so in specified situations could entitle Encore to terminate the merger agreement and to be paid a termination fee of $120 million.

RISKS RELATING TO THE COMBINED COMPANY AFTER THE MERGER

The combined company may experience an impairment of its goodwill.

We expect a significant increase to our existing goodwill in connection with consummation of the merger and the allocation of the purchase price thereto. We test goodwill for impairment annually during the fourth quarter, or between annual tests if an event occurs or circumstances change that may indicate the fair value of a reporting unit is less than the carrying amount. The need to test for impairment can be based on several indicators, including but not limited to a significant reduction in the price of oil or natural gas, a full cost ceiling write-down of oil and natural gas properties, unfavorable revisions to oil and natural gas reserves and significant changes in the expected timing of production, or changes in the regulatory environment.

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

See Item 1. "Business – 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 12, "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

In connection with our proposed acquisition of Encore (the "Merger"), three shareholder lawsuits styled as class actions have been filed against Encore and its board of directors. The lawsuits are entitled Sanjay Israni, Individually and On Behalf of All Others Similarly Situated vs. Encore Acquisition Company et al. (filed November 4, 2009 in the District Court of Tarrant County, Texas), Teamsters Allied Benefit Funds, Individually and On Behalf of All Others Similarly Situated vs. Encore Acquisition Company et al. (filed November 5, 2009 in the Court of Chancery in the State of Delaware) and Thomas W. Scott, Jr., individually and on behalf of all others similarly situated v. Encore Acquisition Company et al. (filed November 6, 2009 in the District Court of Tarrant County, Texas). The Teamsters and Scott lawsuits also name Denbury as a defendant. The complaints generally allege that (1) Encore's directors breached their fiduciary duties in negotiating and approving the Merger and by administering a sale process that failed to maximize shareholder value and (2) Encore, and, in the case of the Teamsters and Scott complaints, Denbury aided and abetted Encore's directors in breaching their fiduciary duties. The Teamsters complaint also alleges that Encore's directors and executives stand to receive substantial financial benefits if the transaction is consummated on its current terms. The plaintiffs in these lawsuits seek, among other things, to enjoin the Merger and to rescind the Merger Agreement. Encore and Denbury have entered into a Memorandum of Understanding with the plaintiffs in these lawsuits agreeing in principle to the settlement of the lawsuits based upon inclusion in our joint proxy statement/prospectus dated February 5, 2010, mailed to shareholders of Denbury and Encore in connection with their respective shareholder meetings to approve the Merger, of additional disclosures requested by the plaintiffs, and agreeing that the parties to the lawsuits will use best efforts to enter into a definitive settlement agreement, which has not yet occurred pending completion of limited discovery, and to seek court approval for the settlement which would be binding on all Encore shareholders who do not opt-out of the settlement.

A shareholder suit regarding a compensation matter brought as a derivative action on behalf of Denbury against Denbury's board of directors, entitled Harbor Police Retirement System v. Gareth Roberts, et al, in the District Court of Dallas County, Texas, was amended during January 2010 to generally allege breach of the Denbury directors' fiduciary duties based upon the further allegation that the directors approved an unreasonably high purchase price in the Merger. At a hearing held on March 1, 2010, the Court granted plaintiff's motion for leave to amend its petition to add putative class action claims, including disclosure claims related to the joint proxy statement/prospectus. The plaintiff seeks monetary damages and equitable relief, which in the latter case includes enjoining the Denbury shareholders meeting. The Court, however, abated these merger and disclosure claims in favor of the *Israni* and *Scott* complaints in Tarrant County, Texas (referenced above), and in light of such abatement the Court denied as moot plaintiff's motion to enjoin the Denbury shareholders meeting. Denbury believes that its directors have a valid defense to all claims against them, and that the other allegations in this suit are without merit. Denbury and its directors intend to defend this litigation vigorously.

We are involved in various other lawsuits, claims and regulatory proceedings incidental to our businesses. While we currently believe that the ultimate outcome of these proceedings, individually and in the aggregate, will not have a material adverse effect on our financial position or overall trends in results of operations or cash flows, litigation is subject to inherent uncertainties. If an unfavorable ruling 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. RESERVED

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

Common Stock Trading Summary

The following table summarizes the high and low reported sales prices on days in which there were trades of Denbury's common stock on the New York Stock Exchange ("NYSE"), for each quarterly period for the last two fiscal years. As of February 3, 2010, 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 1,341. On February 26, 2010, the last reported sale price of Denbury's common stock, as reported on the NYSE, was $14.08 per share.

	2009		2008	
	High	Low	High	Low
First Quarter	$17.520	$ 9.610	$33.640	$21.760
Second Quarter	18.840	13.390	40.320	27.280
Third Quarter	17.780	12.450	37.240	16.110
Fourth Quarter	17.390	12.510	18.860	5.590

We have never paid any dividends on our common stock, and we currently do not anticipate paying any dividends in the foreseeable future. Also, we are restricted from declaring or paying any cash dividends on our common stock under our bank loan agreement. On December 18, 2009, we issued 11,620,000 shares of Denbury common stock as part of the consideration to a Houston based privately-owned company, to purchase oil and gas assets in the Conroe Field. Under a registration rights agreement signed at the closing of this acquisition, Denbury provided the designees with resale registration rights covering the shares issued in the transaction. The designees have agreed, with limited exceptions, not to sell any of these securities until the earlier of the closing of the acquisition of Encore, the termination of the merger agreement to acquire Encore, or in certain cases June 28, 2010. No other unregistered securities were sold by the Company during 2009.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Shares that May Yet Be Purchased Under the Plan or Programs
October 1 through 31, 2009	3,475	$13.95	—	—
November 1 through 30, 2009	218	14.60	—	—
December 1 through 31, 2009	—	—	—	—
Total	3,693	13.99	—	—

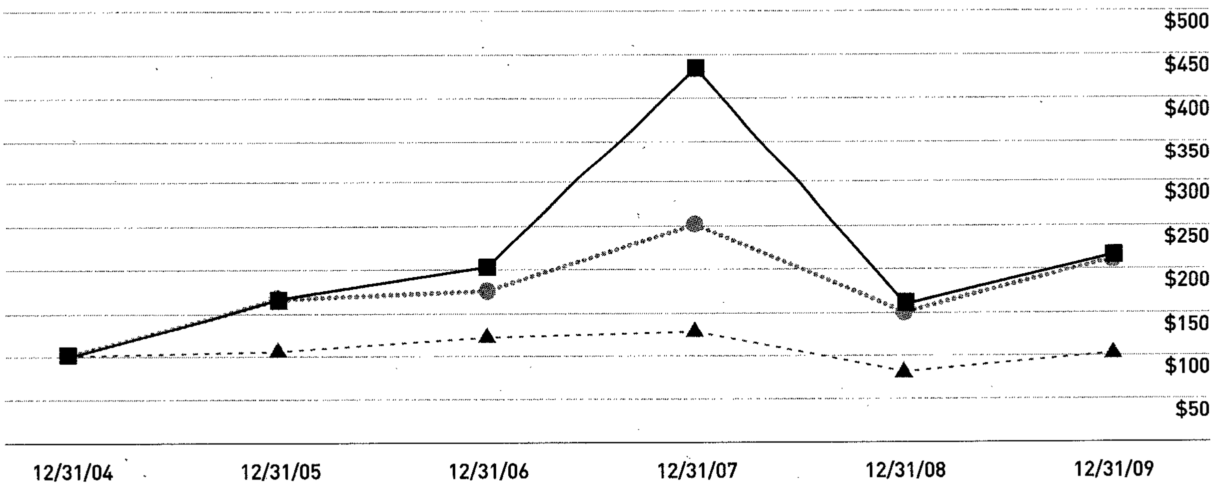
These shares were purchased from employees of Denbury who delivered shares to the company to satisfy their minimum tax withholding requirements related to the vesting of restricted shares.

Share Performance Graph

The following Performance Graph and related information shall not be deemed "soliciting material" or to be "filed" with the Securities and Exchange Commission, 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 filing.

The following graph illustrates changes over the five-year period ended December 31, 2009, 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 results assume $100 was invested on December 31, 2004, and that dividends were reinvested.

Comparison of 5 Year Cumulative Total Return



	December 31,					
	2004	2005	2006	2007	2008	2009
Denbury Resources Inc.	100.00	165.97	202.48	433.52	159.13	215.66
S&P 500	100.00	104.91	121.48	128.16	80.74	102.11
Dow Jones U.S. Exploration and Production	100.00	165.32	174.20	250.27	149.86	210.65

ITEM 6. SELECTED FINANCIAL DATA

In thousands, unless otherwise noted	Year Ended December 31, 2009	2008	2007	2006[1]	2005
Consolidated Statements of Operations Data:					
Revenues	$ 882,493	$ 1,365,702	$ 973,060	$ 731,536	$ 560,392
Net income (loss)[2]	(75,156)	388,396	253,147	202,457	166,471
Net income (loss) per common share:[3]					
Basic	(0.30)	1.59	1.05	0.87	0.74
Diluted	(0.30)	1.54	1.00	0.82	0.70
Weighted average number of common shares outstanding:[3]					
Basic	246,917	243,935	240,065	233,101	223,485
Diluted	246,917	252,530	252,101	247,547	239,267
Consolidated Statements of Cash Flow Data:					
Cash provided by (used by):					
Operating activities	$ 530,599	$ 774,519	$ 570,214	$ 461,810	$ 360,960
Investing activities[4]	(969,714)	(994,659)	(762,513)	(856,627)	(383,687)
Financing activities[5]	442,637	177,102	198,533	283,601	154,777
Production (daily):					
Oil (Bbls)	36,951	31,436	27,925	22,936	20,013
Natural gas (Mcf)	68,086	89,442	97,141	83,075	58,696
BOE (6:1)	48,299	46,343	44,115	36,782	29,795
Unit Sales Price (excluding impact of derivative settlements):					
Oil (per Bbl)	$ 57.75	$ 92.73	$ 69.80	$ 59.87	$ 50.30
Natural gas (per Mcf)	3.54	8.56	6.81	7.10	8.48
Unit Sales Price (including impact of derivative settlements):					
Oil (per Bbl)	$ 68.63	$ 90.04	$ 68.84	$ 59.23	$ 50.30
Natural gas (per Mcf)	3.54	7.74	7.66	7.10	7.70
Costs per BOE:					
Lease operating expenses	$ 18.50	$ 18.13	$ 14.34	$ 12.46	$ 9.98
Production taxes and marketing expenses	2.41	3.76	3.05	2.71	2.54
General and administrative[6]	6.59	3.56	3.04	3.20	2.62
Depletion, depreciation and amortization	13.52	13.08	12.17	11.11	9.09
Proved Reserves:					
Oil (MBbls)	192,879	179,126	134,978	126,185	106,173
Natural gas (MMcf)[7]	87,975	427,955	358,608	288,826	278,367
MBOE (6:1)	207,542	250,452	194,746	174,322	152,568
Carbon dioxide (MMcf)[8]	6,302,836	5,612,167	5,641,054	5,525,948	4,645,702
Consolidated Balance Sheet Data:					
Total assets	$4,269,978	$ 3,589,674	$ 2,771,077	$ 2,139,837	$ 1,505,069
Total long-term liabilities	1,903,951	1,363,539	1,102,066	833,380	617,343
Stockholders' equity[9]	1,972,237	1,840,068	1,404,378	1,106,059	733,662

(1) Effective January 1, 2006, Denbury adopted new guidance issued by the Financial Accounting Standard Board ("FASB") in the "Compensation-Stock Compensation" topic of the FASB Accounting Standards Codification™ ("FASC") which prospectively required Denbury to record compensation expense for stock incentive awards.

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

(3) On December 5, 2007, and October 31, 2005, we split our common stock on a 2-for-1 basis. Information relating to all prior years' shares and earnings per share has been retroactively restated to reflect the stock splits.

(4) During February 2009, we closed our $201 million purchase of Hastings Field, and in December 2009, we closed our $430.7 million purchase of Conroe Field (for $269.8 million in cash and the issuance of 11,620,000 shares of common stock). We sold our Barnett Shale natural gas assets in 2009.

(5) In February 2009, we issued $420 million of 9.75% Senior Subordinated Notes due 2016.

(6) In June 2009, we recorded $10.0 million of expense related to a Founder's Retirement Agreement. During 2009, we recorded $14.2 million related to incentive compensation awards for the management of Genesis. During the fourth quarter of 2009, we recorded $8.7 million in acquisition-related expenses in conjunction with the Encore Merger Agreement.

(7) In December 2007 and February 2008, we sold our Louisiana natural gas assets, and during 2009 we sold our Barnett Shale natural gas assets.

(8) Based on a gross working interests basis and includes reserves dedicated to volumetric production payments of 127.1 Bcf at December 31, 2009, 153.8 Bcf at December 31, 2008, 182.3 Bcf at December 31, 2007, 210.5 Bcf at December 31, 2006, and 237.1 Bcf at December 31, 2005. (See Note 16 to the Consolidated Financial Statements).

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

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

The following discussion and analysis should be read in conjunction with our Consolidated Financial Statements and Notes thereto included in Item 8, "Financial Statements and Supplementary Data." Our discussion and analysis includes forward looking information that involves risks and uncertainties and should be read in conjunction with "Risk Factors" under Item 1A of this report, along with "Forward Looking Information" at the end of this section for information on the risks and uncertainties that could cause our actual results to be materially different than our forward looking statements. The following discussion and analysis does not include information regarding results of operations and financial condition of Encore, which is contained in Encore's Form 10-K for the year ended December 31, 2009, filed by Encore with the SEC on February 25, 2010.

OVERVIEW

We are a growing independent oil and natural gas company engaged in acquisition, development and exploration activities in the U.S. Gulf Coast region. We are the largest oil and natural gas producer in Mississippi, own the largest carbon dioxide ("CO_2") reserves east of the Mississippi River used for tertiary oil recovery, and hold significant operating acreage in properties onshore in Louisiana, Alabama and Southeast Texas. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling, and proven engineering extraction processes, with our most significant emphasis relating to tertiary recovery operations. Our corporate headquarters are in Plano, Texas (a suburb of Dallas), and we have four primary field offices located in Laurel, Mississippi; Jackson, Mississippi; Little Creek, Mississippi; and Alvin, Texas.

During 2009, we entered into several strategic transactions to expand our primary business of CO_2 tertiary operations, as follows:

- purchased Hastings Field in southeast Texas in February;
- purchased Conroe Field in the same area in December;
- on October 31st agreed to acquire Encore Acquisition Company, subject to approval of each company's shareholders on March 9, 2010;
- divested non-strategic operations in the Barnett Shale; and
- entered into an agreement to sell our interests in the General Partner of Genesis Energy, L.P. and subsequently closed this transaction in February 2010.

Each of these transactions, which are further discussed below, supports our strategic emphasis on further developing and expanding our CO_2 tertiary operations and should provide future growth in our CO_2 tertiary operations for many years to come. In addition, during 2009 we invested approximately $538 million in our Green Pipeline, which when finished will transport CO_2 from the end of our NEJD Pipeline, in Louisiana, to our tertiary floods in southeast Texas.

2009 Operating Highlights. We recognized a net loss of $75.2 million during 2009, or ($0.30) per common share, compared to net income of $388.4 million, or $1.59 per common share earned during 2008. The reduction in net income between the two years is primarily due to lower oil and natural gas commodity prices and non-cash expense of $383.0 million ($237.4 million after tax) in 2009 due to the changes in fair value of our commodity derivative contracts. In 2008, we recorded a non-cash gain of $257.6 million ($159.7 million after tax) on the fair value changes in our commodity derivative contracts, which was primarily offset by a $226.0 million ($140.1 million after tax) full cost ceiling test write-down at December 31, 2008.

Oil and natural gas prices continued to be volatile during 2009, but generally trended upward during the year, as compared to the latter part of 2008 when oil and natural gas prices dropped significantly from their highs in mid-2008. Our average revenue per BOE, excluding the impact of oil and natural gas derivative contracts, was $49.16 per BOE in 2009, as compared to $79.42 per BOE in 2008, a 38% decrease between the two periods. Although our production increased between 2008 and 2009, the significant drop in commodity prices resulted in a 36% decrease in our oil and natural gas revenues during 2009 as compared to 2008.

During 2009, our oil and natural gas production averaged 48,299 BOE/d, a 4% increase over the average production for 2008; however, our continuing production excluding the production from our Barnett Shale properties that were sold in 2009 increased 15%. Our largest production increases were attributable to our tertiary oil production and Hastings Field, which we acquired in February 2009, partially offset by (a) the sale of our Barnett Shale natural gas properties; and (b) expected declines in our Mississippi non-tertiary production primarily due to lower Selma Chalk natural gas production as a result of limited drilling activity in 2009, and to a lesser extent due to lower non-tertiary Heidelberg oil production as additional areas of that field were shut-in in order to expand the tertiary flooding to those areas. See "Results of Operations – Operating Results – Production" for more information.

Tertiary oil production averaged 24,343 BOE/d during 2009, representing a 26% increase over our tertiary oil production during 2008. We had strong production increases during 2009 from several of our existing tertiary oil fields, and had initial production response from CO_2 injections at Heidelberg Field during the second quarter of 2009 and at Cranfield Field during the first quarter of 2009. See "Results of Operations – CO_2 Operations" for more information.

Cash settlements received on our commodity derivative contracts during 2009 were $146.7 million, compared to payments of $57.5 million made during 2008. During 2009, we had a non-cash fair value charge on our derivative contracts of $383.0 million, compared to a non-cash fair value gain of $257.6 million in 2008. Coupled together, our total adjustments on derivative contracts resulted in a net change between 2008 and 2009 of $436.3 million of additional expense in 2009.

Our lease operating expenses increased 6% between 2008 and 2009, primarily due to our increasing emphasis on tertiary operations, increasing utility and electrical costs to operate our fields, and increasing lease payments for certain equipment in our tertiary operating facilities. General and administrative expenses increased significantly from 2008 levels due to increased compensation and personnel related costs, incentive compensation awards for certain members of management of Genesis, $10.0 million paid under a Founder's Retirement Agreement, and acquisition related expenses associated with the Encore merger agreement. Interest expense also increased during 2009, due primarily to the February issuance of $420 million of 9.75% Senior Subordinated Notes due 2016 and the pipeline dropdown transactions with Genesis, which were completed mid-2008, offset in part by increasing interest capitalization related to our CO_2 pipelines under construction.

Definitive Merger Agreement to Acquire Encore Acquisition Company. On November 1, 2009, Denbury and Encore announced that we had entered into a definitive merger agreement providing for Encore to merge with and into Denbury, in a stock and cash transaction valued at approximately $4.5 billion at that time, including the assumption of debt and the value of the general partner units and limited partner units held by Encore in Encore MLP. The combined company will continue to be known as Denbury Resources Inc. and will be headquartered in Plano, Texas.

The Merger Agreement was unanimously approved by the boards of directors of both Denbury and Encore. The Merger Agreement contemplates a merger whereby Denbury and Encore have agreed to combine their businesses such that Encore will be merged with and into Denbury, with Denbury surviving the Merger. The Merger is subject to the stockholders of each of Denbury and Encore approving the Merger, including approval by Denbury's stockholders of the issuance of Denbury common stock to be used as Merger consideration. Each company has scheduled a special stockholder meeting on March 9, 2010, for stockholders to vote on the merger.

Under the agreement, Encore stockholders will receive $50.00 per share for each share of Encore common stock, comprised of $15.00 in cash and $35.00 in Denbury common stock, subject to both an election feature and a collar mechanism on the stock portion of the consideration as set forth in more detail below.

Merger Agreement

In calculating the exchange ratio range for the collar mechanism, the Denbury common stock was initially valued at $15.10 per share. The collar mechanism is limited to a 12% upward or downward movement in the Denbury share price. The final number of Denbury shares to be issued will be adjusted based on the volume weighted average price of Denbury common stock on the NYSE for the 20-day trading period ending on the second day prior to closing. Based on this mechanism, if Denbury stock trades between $13.29 and $16.91, the Encore stockholders will receive between

2.0698 and 2.6336 shares of Denbury common stock for each of their shares of Encore common stock, but not higher or lower than these share amounts if Denbury common stock trades outside this range. If Denbury common stock trades outside of this range, the value of the shares of Denbury received will represent either more or less than $35 per share. Based on the number of shares of Encore common stock outstanding as of February 3, 2010, we would issue to Encore stockholders between 115 million and 146 million shares of our common stock in the Merger, which will represent an increase in our aggregate shares outstanding of between 44% and 56%.

The Merger Agreement contains customary covenants by each party to the Merger Agreement and consummation of the Merger is subject to customary conditions. The Merger Agreement also contains certain termination rights for both us and Encore, including, among others, if the Merger has not occurred on or before May 31, 2010 with termination fees in varying amounts payable by us or by Encore based upon specified reasons for termination. See "Business-Definitive Merger Agreement to Acquire Encore Acquisition Company."

Financing of the Merger

We received a financing commitment from J.P. Morgan, subject to customary conditions, to underwrite a new $1.6 billion senior secured revolving credit facility. We have been advised by the co-arrangers of this new senior secured revolving credit facility, J.P. Morgan and Bank of America, N.A. that the syndication phase is complete, and documentation for this facility is being prepared. Subject to final documentation and satisfaction of closing conditions, we anticipate finalizing this facility prior to the Denbury and Encore stockholder meetings. The newly committed financing, coupled with the funds from our recent subordinated debt offering (see next paragraph), will be used to fund the cash portion of the merger consideration (inclusive of payments due to Encore stock option holders), repay amounts outstanding under our existing $750 million revolving credit facility, which had $125 million outstanding as of February 15, 2010, potentially retire and replace a portion of up to $825 million of Encore's senior subordinated notes that are outstanding, all of which have a change of control put option at 101% of par value, repay amounts outstanding under Encore's existing revolving credit facility which had $155 million outstanding as of February 15, 2010, pay Encore's severance costs, pay transaction fees and expenses and provide additional liquidity. The aggregate commitment of the senior secured lenders is a $1.6 billion facility with a term of four years. The new facility is expected to be on substantially the same terms as our existing facility, conformed to current market conditions.

We also received a financing commitment from J.P. Morgan for a $1.25 billion unsecured bridge loan facility; however, this bridge loan facility has been terminated and will not be utilized to fund the Merger as we have instead issued $1 billion of 8.25% Senior Subordinated Notes due 2020. On February 10, 2010, we sold $1 billion of 8.25% Senior Subordinated Notes due 2020 at 100% of par in a public offering. The net proceeds from the notes offering were placed in escrow pending the closing of the Merger, subject to mandatory redemption of the notes if the Merger does not close, and partial redemption of the notes to the extent that three series of Encore outstanding senior subordinated notes are not repurchased. Upon the closing of the Merger, $400 million of the escrowed proceeds will be released to us to finance a portion of the Merger consideration, and the remaining escrowed proceeds will be used to fund repurchases of up to $600 million principal amount of three series of Encore's outstanding senior subordinated notes (or newly issued 8.25% senior notes to the extent not issued to repurchase Encore notes). On February 8, 2010, we initiated a tender offer for these Encore subordinated notes, the closing of which is subject to the closing of the Merger.

Sale of Interests in General Partner of Genesis Energy, L.P. On February 5, 2010, Denbury and one of its subsidiaries sold all of the subsidiary's interests in Genesis Energy, LLC, the general partner of Genesis Energy, L.P., or Genesis, to an affiliate of Quintana Capital Group L.P., for net proceeds of approximately $82 million (including amounts related to Genesis management incentive compensation and other selling costs). This sale gives the buyer control of Genesis' general partner. The sale of Denbury's interest in the general partner does not include the sale of its approximate 10% ownership of Genesis' outstanding common units, which Denbury currently still owns and for which a resale registration statement was filed in January 2010.

Conroe Field Acquisition. On December 18, 2009, we purchased from Wapiti Energy, LLC, Wapiti Operating, LLC and Wapiti Gathering, LLC (collectively, "Wapiti"), a Houston based privately-owned company, oil and natural gas assets in the Conroe Field for total consideration of $422.9 million (after preliminary purchase price adjustments), consisting of $254.2 million in cash and 11,620,000 shares of Denbury common stock, which for the purpose of estimated fair value under FASC "Business Combinations" topic, we utilized the closing stock price on that date of $14.52 per share resulting in a total value of $168.7 million. We also exchanged cash for approximately $15.6 million of escrow account deposits reserved for plugging and abandonment. We have internally estimated that the Conroe Field interests have significant estimated net reserve potential from CO_2 tertiary recovery, the largest EOR potential of our Gulf Coast oil fields. The acquired Conroe Field interests have estimated proved conventional reserves of approximately 18.5 MMBbls at December 31, 2009, nearly all of which are proved developed. The Conroe Field assets are currently producing around 2,500 BOE/d net to our acquired interest.

We have recorded the acquisition of Conroe Field in accordance with the Financial Accounting Standards Board ("FASB") Accounting Standards Codification™ ("FASC") "Business Combinations" topic, which became effective for acquisitions after December 31, 2008. Based on these new rules, we have allocated $304.3 million of the $438.5 million adjusted purchase price (includes escrow deposits) to proved properties, $93.6 million to unevaluated properties, approximately $15.6 million to other assets, $5.7 million to asset retirement obligations and the net remaining $30.7 million to goodwill. See further discussion on this acquisition in Note 2 to the Consolidated Financial Statements.

Sale of Barnett Shale Natural Gas Assets. In May 2009, we entered into an agreement to sell 60% of our Barnett Shale assets to Talon Oil and Gas LLC ("Talon"), a privately held company, for $270 million (before closing adjustments). On June 30, 2009, we completed approximately three-quarters of the sale, and closed the remaining portion of the sale on July 15, 2009. Net proceeds were $259.8 million (after closing adjustments, and net of $8.1 million paid to Talon for natural gas swaps transferred in the sale). We did not record a gain or loss on the sale in accordance with the full cost method of accounting.

On December 30, 2009, we sold our remaining 40% interest in our Barnett Shale natural gas assets to Talon for $210 million in cash, subject to closing adjustments. The proceeds of the sale were used to reduce outstanding bank debt. The sale was structured as a deferred like-kind exchange in conjunction with Denbury's purchase of Conroe Field that closed on December 18, 2009.

Mid-Year Management Changes. On June 30, 2009, under a management succession plan adopted by our Board of Directors and announced on February 5, 2009, Gareth Roberts, the Company's founder, relinquished his position as President and CEO and became Co-Chairman of the Board of Directors and assumed a non-officer role as the Company's Chief Strategist. Phil Rykhoek, previously Senior Vice President and Chief Financial Officer, became Chief Executive Officer; Tracy Evans, previously Senior Vice President – Reservoir Engineering, became President and Chief Operating Officer; and Mark Allen, previously Vice President and Chief Accounting Officer, became Senior Vice President and Chief Financial Officer.

In connection with Mr. Roberts' retirement as CEO and President of the Company, Mr. Roberts and the Company entered into a Founder's Retirement Agreement (the "Agreement"). Under this Agreement, Mr. Roberts received $3.65 million in cash and the Company issued to him $6.35 million of the Company's 9.75% Senior Subordinated Notes due 2016. As part of the Agreement, there are restrictions that prohibit Mr. Roberts from trading these notes for two years, and he has entered into a non-compete arrangement with the Company through 2013. Mr. Roberts will continue to provide services to the Company as Co-Chairman of the Board of Directors and in a non-officer role as Chief Strategist.

Purchase of Hastings Field. On February 2, 2009, we closed the acquisition of Hastings Field located near Houston, Texas, for approximately $201 million in cash. Hastings Field is a significant potential tertiary oil flood that we plan to flood with CO_2 delivered from Jackson Dome using our Green Pipeline, which is currently under construction. We originally entered into an agreement in November 2006 with a subsidiary of Venoco, Inc., that gave us the option to purchase its interest in the Hastings Field. As consideration for the purchase option, we made total payments of $50 million which makes our aggregate purchase price $251 million. The seller retained a 2% override and reversionary interest of approximately 25% following payout, as defined in the purchase agreement. We plan to commence flooding the field with CO_2 beginning in 2011, after completion of our Green Pipeline and construction of field recycling facilities. Under the purchase agreement, we are required to make net capital expenditures in this field totaling $179 million over the next five years, including our first obligation of $26.8 million during 2010, and are committed to begin CO_2 injections averaging 50 MMcf/d by the fourth quarter of 2012. Production from this field averaged 1,956 BOE/d during 2009, all of which was non-tertiary production. At December 31, 2009, the Hastings Field had proved reserves of 8.9 MMBbls.

We have recorded the acquisition of Hastings Field in accordance with FASC "Business Combinations" topic, which became effective for acquisitions after December 31, 2008. Based on these new rules, we have allocated $107.6 million of the $246.8 million adjusted purchase price to proved properties, approximately $2.4 million to land, oilfield equipment and other related assets, $2.0 million to asset retirement obligations and the net remaining $138.8 million to goodwill. See further discussion regarding this acquisition in Note 2 to the Consolidated Financial Statements.

February 2009 Subordinated Debt Issuance. On February 13, 2009, we issued $420 million of 9.75% Senior Subordinated Notes due 2016 (the "Notes"). The Notes were sold to the public at 92.816% of par, plus accrued interest from February 13, 2009, which equates to an effective yield to maturity of approximately 11.25% (before offering expenses). Interest on the Notes will be paid on March 1 and September 1 of each year. The Notes will mature on March 1, 2016. We used the net proceeds from the offering of approximately $381.4 million to repay most of the then outstanding debt on our bank credit facility. We issued an additional $6.35 million of Notes to Mr. Roberts on June 30, 2009 (see "Mid-Year Management Changes" above).

CAPITAL RESOURCES AND LIQUIDITY

General

During 2009, we took several steps to ensure that we had adequate capital resources and liquidity in order to fund our capital expenditure program and to complete two strategic acquisitions, the Hastings Field and the Conroe Field. Those steps included the issuance of $420 million of 9.75% Senior Subordinated Notes in February 2009, the sale of 60% of our Barnett Shale assets in mid-2009, and the sale of the remaining 40% of our Barnett Shale assets during December 2009. We used the $381.4 million net proceeds from the February 2009 Notes issuance to repay the majority of our then-outstanding bank debt, and we did the same with the proceeds from our December 2009 Barnett Shale sale, freeing up our credit line for future capital needs.

Denbury Stand-Alone

We currently estimate our 2010 capital spending will be approximately $650 million, excluding capitalized interest and net of equipment leases, and any expenditures related to the Encore acquisition. Our current 2010 capital budget includes approximately $74 million to be spent in the Jackson Dome area, $159 million to be spent on our CO_2 pipelines and approximately $365 million allocated for tertiary oil field expenditures. This estimate also assumes that we fund approximately $50 million of budgeted equipment purchases with operating leases, which is dependent upon securing acceptable financing. If we do not enter into a total of $50 million of operating leases during 2010, our net capital expenditures would increase accordingly, and we would anticipate funding those additional capital expenditures under our bank credit line. We did not enter into as many operating leases during 2009 as we had anticipated, leasing approximately $49 million of equipment out of a projected total of $100 million, which resulted in a corresponding net increase in capital expenditures and bank debt. Potentially, during 2010 we could lease all or a portion of this equipment.

Based on oil and natural gas commodity futures prices as of late February 2010 and our current 2010 production forecasts, our stand-alone 2010 capital budget is expected to be $150 million to $250 million greater than our anticipated cash flow from operations on a stand-alone basis. We plan to fund this shortfall with cash generated from the sale of our general partnership interest in Genesis (see "Sale of Interests in General Partner of Genesis Energy, L.P." above), the anticipated sale of our limited partnership units in Genesis Energy, L.P., and the remainder from borrowings under our bank facility. As of February 15, 2010, we had $125 million of bank debt outstanding on our $750 million committed bank facility, leaving us significant incremental borrowing capacity to fund any shortfall.

Combined Company — Post Denbury/Encore Merger

Assuming the successful completion of the Encore acquisition in early March 2010, our currently planned 2010 capital expenditure budget for the combined companies would increase to $1 billion. Currently, this incremental $350 million of capital expenditures is budgeted to be spent as follows: (1) approximately $142 million to drill or participate in drilling or refracing of 55 to 75 wells in the Bakken area of North Dakota; (2) approximately $99 million to drill and complete 6 to 8 operated wells and participate in 20 to 25 non-operated wells in the Haynesville and other East Texas fields; (3) approximately $35 million on Encore's Rocky Mountain legacy oil fields; and (4) approximately $74 million on drilling and completion activities in Encore's Permian Basin and Mid-Continent region. Based on oil and gas commodity prices as of late February 2010, our current estimated production forecasts on a combined basis for all of 2010, and before any asset sales, our 2010 combined capital budget is expected to be $150 million to $250 million greater than our anticipated combined cash flow from operations, assuming a full year of operations.

As discussed above in "Overview – Definitive Merger Agreement to Acquire Encore Acquisition Company," the primary source of cash for the proposed acquisition of Encore would be a new $1.6 billion bank credit facility, which would replace our existing facility, and $1 billion of recently issued 8.25% Senior Subordinated Notes due 2020. We structured the financing of the acquisition to provide $600 million to $700 million of availability on our new $1.6 billion bank credit facility upon closing the transaction; this would provide a level of liquidity similar to that available to us prior to the transaction, and a portion of those funds would be available for the expanded capital expenditures discussed above. In addition, during 2010 we plan to sell between $500 million and $1 billion of oil and gas properties to cover capital expenditures in excess of cash flow from operations during 2010, to reduce debt levels, and to provide additional liquidity. During 2009, we also entered into oil and natural gas commodity derivative contracts through 2011 in order to protect our future cash flows. See Note 10 to the Consolidated Financial Statements for further details regarding pricing and volumes for these commodity derivative contracts.

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 2010, we have contracted for certain capital expenditures, including construction of most of the Green Pipeline already in progress and two drilling rigs, and therefore we cannot eliminate all of our capital commitments without penalties (refer to "Off-Balance Sheet Arrangements – Commitments and Obligations" for further information regarding these commitments).

As part of our semi-annual bank review, on October 1, 2009, our bank borrowing base and commitment amounts were left unchanged at $900 million and $750 million, respectively. The borrowing base represents the amount that can be borrowed from a credit standpoint while the commitment amount is the amount the banks have committed to fund pursuant to the terms of the credit agreement. As a result of the sale of our remaining Barnett Shale properties in December 2009, the banks performed another redetermination of our borrowing base and left the commitment amount unchanged at $750 million. If for some reason the Merger is not completed, we anticipate this credit line will be sufficient for our 2010 plans, and do not expect our bank credit line to be reduced by our banks unless commodity prices were to decrease significantly from current levels. However, assuming the closing of the Merger, this credit facility will be replaced with the newly committed $1.6 billion four-year revolving credit facility discussed above in "Overview – Definitive Merger Agreement to Acquire Encore Acquisition Company."

Capital Expenditure Summary. The following table of capital expenditures includes accrued capital for each period. Our cash expenditures were $76.0 million higher in the 2009 period, $59.2 million lower in the 2008 period and $0.4 million higher in the 2007 period than the amounts listed below due to the increase (decrease) in our capital accruals in those periods. For the 2009 period, oil and natural gas property acquisitions include $168.7 million of Denbury common stock issued in the purchase of Conroe Field, representing 11,620,000 common shares valued at the closing stock price of $14.52 per share on the date of acquisition, and approximately $169.5 million of the combined acquisition cost of Hastings Field and Conroe Field which was assigned to goodwill as determined under the FASC "Business Combinations" topic.

In thousands	Year Ended December 31, 2009	2008	2007
Capital expenditures:			
Oil and natural gas exploration and development:			
Drilling	$ 45,403	$ 244,841	$313,258
Geological, geophysical and acreage	15,004	18,183	22,829
Facilities	154,772	170,263	118,003
Recompletions	73,968	140,451	141,264
Capitalized interest	14,350	17,627	18,305
Total oil and natural gas exploration and development expenditures	303,497	591,365	613,659
Oil and natural gas property acquisitions	621,517	31,367	49,077
Total oil and natural gas capital expenditures	925,014	622,732	662,736
CO_2 capital expenditures:			
CO_2 pipelines	542,654	343,043	103,401
CO_2 producing fields	33,302	108,312	65,701
Capitalized interest	54,246	11,534	2,080
Total CO_2 capital expenditures	630,202	462,889	171,182
Total	$1,555,216	$1,085,621	$833,918

Our 2009 capital expenditures, including the $169.5 million of goodwill incurred in 2009 and the $76.0 million reduction in accrued capital expenditures, were funded with $530.6 million of cash flow from operations, $516.8 million in net proceeds from the sale of oil and natural gas properties, $381.4 million in net proceeds from the February issuance of senior subordinated debt, $168.7 million from the issuance of 11,620,000 shares of Denbury common stock in the acquisition of Conroe Field and $50.0 million in net bank borrowings.

Our 2008 capital expenditures were funded with $774.5 million of cash flow from operations, $225 million from the drop-down of CO_2 pipelines to Genesis, and $51.7 million from property sales proceeds.

Our 2007 capital expenditures were funded with $570.2 million of cash flow from operations, $150.0 million from the April 2007 issuance of subordinated debt, $135.8 million from property sales proceeds, and $16.0 million of net bank borrowings.

Off-Balance Sheet Arrangements – Commitments and Obligations. At December 31, 2009, our dollar denominated payment obligations that are not on our balance sheet include our operating leases, which at year-end 2009 totaled $162.2 million (including $147.8 million of original equipment costs) relating primarily to the lease financing of certain equipment for CO_2 recycling facilities at our tertiary oil fields. We also have several leases relating to office space and other minor equipment leases. At December 31, 2009, we had a total of $10.5 million of letters of credit outstanding under our bank credit agreement. Additionally, we have dollar denominated 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 forecasted in our proved reserve reports. For a further discussion of our future development costs and proved reserves, see the table of our contractual obligations below.

On February 2, 2009, we closed our $201 million purchase of Hastings Field. Under the agreement, we are required to make aggregate cumulative capital expenditures in this field of approximately $179 million over the next five years cumulating as follows: $26.8 million by December 31, 2010, $71.5 million by December 31, 2011, $107.2 million by December 31, 2012, $142.9 million by December 31, 2013, and $178.7 million by December 31, 2014. If we fail to spend the required amounts by the due dates, we are required to make a cash payment equal to 10% of the cumulative shortfall at each applicable date. During 2009, we made capital expenditures related to CO_2 flood development at Hastings totaling $1.7 million. Further, we are committed to injecting at least an average of 50 MMcf/d of CO_2 (total of purchased and recycled) in the West Hastings Unit for the 90-day period prior to January 1, 2013. If such injections do not occur, we must either (1) relinquish our rights to initiate (or continue) tertiary operations and reassign to Venoco all assets previously purchased for the value of such assets at that time based upon the discounted value of the field's proved reserves using a 20% discount rate, or (2) make an additional payment of $20 million in January 2013, less any payments made for failure to meet the capital spending requirements as of December 31, 2012, and a $30 million payment for each subsequent year (less amounts paid for capital expenditure shortfalls) until the CO_2 injection rate in the Hastings Field equals or exceeds the minimum required injection rate. We currently anticipate that we will be able to meet the requirements under this agreement.

We currently have long-term commitments to purchase CO_2 from eight proposed gasification plants; four are in the Gulf Coast region and four are in the Midwest region (Illinois, Indiana and Kentucky). The Midwest plants are not only conditioned on the specific plants being constructed, but also upon Denbury contracting additional volumes of CO_2 for purchase in the general area of the proposed plants that would provide an acceptable economic rate-of-return on the CO_2 pipeline. If all of these plants were to be built, these CO_2 sources are currently anticipated to provide us with aggregate CO_2 volumes of 1.2 Bcf/d to 1.9 Bcf/d. Due to the current economic conditions, the earliest we would expect any plant to be completed and providing CO_2 would be 2014, and there is some doubt as to whether they will be constructed at all. Several of these plants are seeking funds from government sources, which if achieved, could increase the probability that the plants are ultimately constructed. The base price of CO_2 per Mcf from these CO_2 sources varies by plant and location, but is generally higher than our most recent all-in cost of CO_2 from our natural source (Jackson Dome) using current oil prices. Prices for CO_2 delivered from these projects are expected to be competitive with the cost of our natural CO_2 after adjusting for our estimates of future prices for our share of potential carbon emissions reduction credits. If all eight plants are built, the aggregate purchase obligation for this CO_2 would be around $280 million per year, assuming a $70 per barrel oil price, before any potential savings from our share of carbon emissions reduction credits. All of the contracts have price adjustments that fluctuate based on the price of oil. Construction has not yet commenced on any of these plants, and their construction is contingent on the satisfactory resolution of various issues, including financing. While it is likely that not every plant currently under contract will be constructed, there are several other plants under consideration that could provide CO_2 to us that would either supplement or replace some of the CO_2 volumes from the eight proposed plants for which we currently have CO_2 purchase contracts. We are having ongoing discussions with several of these other potential sources.

As discussed above under "Overview – Definitive Merger Agreement to Acquire Encore Acquisition Company," the Encore Merger Agreement contains certain termination rights for both Denbury and Encore, including, among others, if the Merger is not completed by May 31, 2010. In the event of a termination of the Merger Agreement under certain circumstances, Encore may be required to pay Denbury a termination fee of either $60 million or $120 million, or Denbury may be required to pay Encore a termination fee of either $60 million, $120 million or $300 million, in each case depending on the circumstances of the termination. In addition, fee letters executed in connection with the financing commitment from JP Morgan require Denbury to pay up to approximately $48 million in fees if the Merger is not consummated and the loans do not close.

A summary of our obligations at December 31, 2009, is presented in the following table. Contingent termination fees in connection with the Merger are discussed above. This table does not include the $1 billion of 8.25% Senior Subordinated Notes due 2020 issued in February 2010, the $1.6 billion newly committed bank revolving credit agreement, or any contractual obligations of Encore.

In thousands	Payments Due by Period Total	2010	2011	2012	2013	2014	Thereafter
Contractual Obligations:							
Subordinated debt[a]	$ 951,350	$ —	$ —	$ —	$225,000	$ —	$ 726,350
Senior bank loan[a]	125,000	—	125,000	—	—	—	—
Estimated interest payments on subordinated debt and Senior Bank Loan[a]	451,156	84,632	83,540	80,944	68,230	64,069	69,741
Commitment, transaction, and advisory fees related to financing of the Encore merger[b]	47,892	47,892	—				
Pipeline financing lease obligations[c]	559,056	31,759	33,205	33,438	33,518	33,513	393,623
Operating lease obligations	162,161	27,566	26,621	23,248	20,544	17,145	47,037
Capital lease obligations[d]	7,314	1,974	1,974	1,272	700	673	721
Capital expenditure obligations[e]	229,548	78,006	44,337	35,735	35,735	35,735	—
Derivative contracts payment[f]	88,006	86,986	1,020	—	—	—	—
Other Cash Commitments:							
Future development costs on proved oil and gas reserves, net of capital obligations[g]	754,469	197,640	208,603	128,380	91,381	36,823	91,642
Future development cost on proved CO_2 reserves, net of capital obligations[h]	121,467	12,467	11,000	—	—	11,000	87,000
Asset retirement obligations[i]	134,486	1,585	1,316	740	983	174	129,688
Total	$3,631,905	$570,507	$536,616	$303,757	$476,091	$199,132	$1,545,802

(a) These long-term borrowings and related interest payments are further discussed in Note 6 to the Consolidated Financial Statements. This table assumes that our long-term debt is held until maturity.

(b) Represents the minimum estimated fees payable to JP Morgan for financing commitments related to the proposed acquisition of Encore if the Encore Merger does not close. If the Merger closes, these fees would be increased to approximately $95 million.

(c) 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 with Genesis were entered into in 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 $308 million of these payments represent interest. See Note 3 to the Consolidated Financial Statements.

(d) Represents future minimum cash commitments of $4.7 million to Genesis under capital leases in place at December 31, 2009, primarily for transportation of crude oil and CO_2, and $2.6 million for office space and rental equipment. Approximately $1.4 million of these payments represents interest.

(e) Represents future cash commitments under contracts in place as of December 31, 2009, primarily for pipe, pipeline construction 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 2010 is currently set at $650 million, exclusive of acquisitions and capitalized interest. In certain cases we have the ability to terminate contracts for equipment in which case we would only be liable for the cost incurred by the vendor up to that point; however, as we currently do not anticipate cancelling those contracts these amounts include our estimated payments under those contracts. We also have recurring expenditures for such things as accounting, engineering and legal fees, software maintenance, subscriptions, and other overhead type items. Normally these expenditures do not change materially on an aggregate basis from year to year and are part of our general and administrative expenses. We have not attempted to estimate the amounts of these types of recurring expenditures in this table as most could be quickly cancelled with regard to any specific vendor, even though the expense itself may be required for ongoing normal operations of the Company.

(f) Represents the estimated future payments under our oil and natural gas derivative contracts based on the futures market prices as of December 31, 2009. These amounts will change as oil and natural gas commodity prices change. The estimated fair market value of our oil and natural gas commodity derivatives at December 31, 2009 was a $128.7 million net liability. 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 10 to the Consolidated Financial Statements.

(g) Represents projected capital costs as scheduled in our December 31, 2009 proved reserve report that are necessary in order to recover our proved oil and natural gas reserves. These are not contractual commitments and are net of any other capital obligations shown under "Contractual Obligations" in the table above.

(h) Represents projected capital costs as scheduled in our December 31, 2009 proved reserve report that are necessary in order to recover our proved CO_2 reserves from our CO_2 source wells used to produce CO_2 for our tertiary operations. These are not contractual commitments and are net of any other capital obligations shown above.

(i) Represents the estimated future asset retirement obligations on an undiscounted basis. The present discounted asset retirement obligation is $54.3 million, as determined under the "Asset Retirement and Environmental Obligations" topic of the FASC, and is further discussed in Note 4 to the Consolidated Financial Statements.

Long-term contracts 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 pursuant to three volumetric production payments ("VPPs") (see Note 3 to the Consolidated Financial Statements). Based upon the maximum amounts deliverable as stated in the industrial contracts and the volumetric production payments, we estimate that we may be obligated to deliver up to 433 Bcf of CO_2 to these customers over the next 18 years; however, since the group as a whole has historically taken less CO_2 than the maximum allowed in their contracts, based on the current level of deliveries, we project that our commitment would likely be reduced to approximately 165 Bcf. The maximum volume required in any given year is approximately 136 MMcf/d, although based on our current level of deliveries this would likely be reduced to approximately 66 MMcf/d. Given the size of our proved CO_2 reserves at December 31, 2009 (approximately 6.3 Tcf before deducting approximately 127.1 Bcf for the three VPPs), our current production capabilities and our projected levels of CO_2 usage for our own tertiary flooding program, we believe that we will be able to meet these delivery obligations.

RESULTS OF OPERATIONS

CO_2 Operations

Overview. Since we acquired our first carbon dioxide tertiary flood in Mississippi in 1999, we have gradually increased our emphasis on these types of operations. During this time, we have learned a considerable amount about tertiary operations and working with carbon dioxide. Our tertiary operations have grown to the point that approximately 65% of our December 31, 2009 proved reserves are proved tertiary oil reserves, almost 65% of our forecasted 2010 production is expected to come from tertiary oil operations (on a BOE basis), and almost all of our 2010 capital expenditures are related to our current or future tertiary operations. We particularly like this play as (i) it has a lower risk as we are working with oil fields that have significant historical production and data, (ii) it provides a reasonable rate of return at relatively low oil prices (we estimate our economic break-even before corporate overhead and expenses on these projects at current oil prices is in the range of the mid-thirties, depending on the specific field and area), and (iii) we have virtually no competition for this type of activity in our geographic area. Generally, from East Texas to Florida, there are no known significant natural sources of CO_2 in the Gulf Coast area except our own, and these large volumes of CO_2 that we own drive the play. In addition, 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 provide an economical way to sequester CO_2. We have acquired several old oil fields in our areas of operations with potential for tertiary recovery and plan to acquire additional fields, and we are continuing to expand our CO_2 pipeline infrastructure to transport CO_2.

We talk about our tertiary operations by labeling operating areas or groups of fields as Phases. Phase 1 is in Southwest Mississippi and includes several fields along our 183-mile NEJD CO_2 Pipeline that we acquired in 2001. The current tertiary fields in this area are Little Creek, Mallalieu, McComb, Brookhaven and Lockhart Crossing. Phase 2, which began with the early 2006 completion of the Free State CO_2 Pipeline to East Mississippi, includes Eucutta, Soso, Martinville and Heidelberg Fields. Tinsley Field, which is located northwest of Jackson, Mississippi, and was acquired in January 2006, is our Phase 3 and is serviced by that portion of the Delta CO_2 Pipeline completed in January 2008. Phase 4 includes Cranfield and Lake St. John Fields, two fields near the Mississippi/Louisiana border located west of the Phase I fields, and Phase 5 is Delhi Field, a Louisiana field we acquired in 2006, located southwest of Tinsley Field. Flooding in Phase 5 began in November 2009 upon completion of the Delta CO_2 Pipeline from Tinsley to Delhi. Our first tertiary oil response from Delhi Field is expected near mid-2010. Citronelle Field in Southwest Alabama, another field acquired in 2006, is our Phase 6, which will require an extension to the Free State CO_2 Pipeline or another pipeline depending on the ultimate CO_2 source for this field, the timing of which is uncertain at this time. Our last three currently existing phases will require completion of our proposed Green Pipeline, a 320-mile CO_2 pipeline that will run from Southern Louisiana to near Houston, Texas, and is scheduled for completion in 2010. Hastings Field, a field we purchased in February 2009 (see "Commitments and Contingencies"), is our Phase 7, the Seabreeze Complex, acquired in 2007, will be our Phase 8 and Conroe Field, a field we purchased in December 2009 (see "Overview – Conroe Field Acquisition") will be our Phase 9. We anticipate initiating CO_2 injections at Oyster Bayou Field (Phase 8) mid-2010 and at Hastings Field (Phase 7) late 2010 or early 2011.

CO_2 Resources. Since we acquired the Jackson Dome CO_2 source field located near Jackson, Mississippi, in 2001, we have continued to develop the field and have increased the proven CO_2 reserves from approximately 800 Bcf at the time of the acquisition to approximately 6.3 Tcf as of December 31, 2009. During 2009, we drilled one additional CO_2 source well, and we increased our CO_2 reserves by approximately 1 Tcf, more than offsetting the 249 Bcf of CO_2 produced during the year. The estimate of 6.3 Tcf of proved CO_2 reserves is based on 100% ownership of the CO_2 reserves, of which Denbury's net revenue interest ownership is approximately 5.0 Tcf. Both reserve estimates are included in the evaluation of proven CO_2 reserves prepared by DeGolyer and MacNaughton. In discussing the available CO_2 reserves, we make reference to the gross amount of proved reserves, as this is the amount that is available for Denbury's tertiary recovery programs, industrial users, and volumetric production payments with Genesis, as Denbury is responsible for distributing the entire CO_2 production stream for all of these uses. We currently estimate that it will take approximately 2.2 Tcf of CO_2 to develop and produce the proved tertiary recovery reserves we have recorded at December 31, 2009, in Phases 1-4.

Today, we own every known producing CO_2 well in the region, providing us a significant strategic advantage in the acquisition of other properties in Mississippi, Louisiana and Texas that could be further exploited through tertiary recovery. As of February 22, 2010, we estimate that we are capable of producing approximately 1 Bcf/d of CO_2, approximately 9 times the rate that we were capable of producing at the time of our initial acquisition in 2001. We continue to drill additional CO_2 wells, with three more wells planned for 2010 in order to further increase our proved CO_2 reserves and production capacity. Our drilling activity at Jackson Dome will continue beyond 2010 as our current forecasts for the existing nine phases suggest that we will need approximately 1.4 Bcf/d of CO_2 production by 2017.

In addition to using CO_2 for our tertiary operations, we sell CO_2 to third party industrial users under long-term contracts. Most of these industrial contracts have been sold to Genesis along with the sale of volumetric production payments for the CO_2. Our average daily CO_2 production during 2007, 2008 and 2009 was approximately 493 MMcf/d, 637 MMcf/d and 683 MMcf/d, respectively, of which approximately 81% in 2007, 86% in 2008 and 87% in 2009 was used in our tertiary recovery operations, with the balance delivered to Genesis under the volumetric production payments or sold to third party industrial users. During February 2010, our CO_2 production averaged 800 MMcf/d.

We spent approximately $0.17 per Mcf in operating expenses to produce our CO_2 during 2009, less than our 2008 average of $0.22 per Mcf and our 2007 average of $0.21 per Mcf, with the decrease due primarily to decreased CO_2 royalty expense as a result of lower oil prices. Our CO_2 costs peaked at $0.27 per Mcf in the second quarter of 2008, corresponding to the peak in oil prices, but decreased during the fourth quarter of 2008 to an average of approximately $0.15 per Mcf as a result of the decline in oil prices. Our estimated total cost per thousand cubic feet of CO_2 during 2009 was approximately $0.25 per Mcf, after inclusion of depreciation and amortization expense related to the CO_2 production, as compared to approximately $0.30 per Mcf during 2008 and $0.29 per Mcf during 2007.

During 2009, we announced that we had initiated a comprehensive feasibility study of a possible long-term CO_2 pipeline project that would connect proposed gasification plants in the Midwest to the Company's existing CO_2 pipeline infrastructure in Mississippi or Louisiana. Two of the proposed plants are in the term-sheet negotiation phase of a U.S. Department of Energy Loan Guarantee Program (see "Off-Balance Sheet Obligations – Commitments and Obligations") which still require successful finalization of negotiations with the Department of Energy ("DOE") to receive such guarantees. The Illinois Department of Commerce and Economic Opportunity provided financial assistance for the feasibility study for the Illinois portion of the pipeline. The feasibility study was undertaken to determine the most likely pipeline route, the estimated costs of constructing such a pipeline, and review regulatory, legal and permitting requirements. Our current preliminary estimates suggest this would be a 500- to 700-mile pipeline system with a preliminary cost estimate of approximately $1.0 billion, based on the cost of other pipelines we have recently built or have under construction. We have completed the initial feasibility study of this Midwest pipeline, and are evaluating market conditions, potential financing opportunities and construction of the proposed gasification projects. It is currently uncertain whether or not we will build such a pipeline, but this future decision will be highly dependent upon whether or not the proposed gasification plants will be constructed and the economic feasibility of the overall project.

A third proposed gasification plant to be built along the Gulf Coast of Mississippi, for which Denbury has a CO_2 purchase contract, was also selected by the loan guarantee program. The Company plans to commence a pipeline study for this proposed plant, which would likely be a 110-mile pipeline that connects to the existing Free State Pipeline.

In addition to our natural source of CO_2 and the proposed gasification plants discussed above (see "Off-Balance Sheet Arrangements – Commitments and Obligations"), we continue to have ongoing discussions with owners of existing plants of various types that emit CO_2 which we may be able to purchase. In order to capture such volumes, we (or the plant owner) would need to install additional equipment, which includes at a minimum, compression and dehydration facilities. Most of these existing plants emit relatively small volumes of CO_2, generally less than the proposed gasification plants, but such volumes may still be attractive if the source is located near our Green Pipeline. The capture of CO_2 could also be influenced by potential federal legislation, which could impose economic penalties for the emission of CO_2. We believe that we are a likely purchaser of CO_2 produced in our area of operations because of the scale of our tertiary operations, our CO_2 pipeline infrastructure, and our large natural source of CO_2 (Jackson Dome), which can act as a swing CO_2 source to balance CO_2 supply and demand.

Overview of Tertiary Economics. When we began our tertiary operations several years ago, they were generally economic at oil prices below $20 per Bbl, although the economics varied by field. Our costs have escalated during the last few years due to general cost inflation in the industry and higher oil prices, and we estimate that our current break-even, before corporate overhead and interest, is in the mid-thirties per barrel if oil prices remain at their current level (approximately $70 per barrel). Our inception-to-date finding and development costs (including future development and abandonment costs but excluding expenditures on fields without proven reserves) for our tertiary oil fields through December 31, 2009, are approximately $12.68 per BOE. Currently, we forecast that most of these costs will average less than $10 per BOE over the life of each field, depending on the state of a particular field at the time we begin operations, the amount of potential oil, the proximity to a pipeline or other facilities, and other factors. The finding and development costs to date do not include additional probable reserves in fields with current proved reserves. Our operating costs for tertiary operations are highly dependent on commodity prices and could range from $15 per BOE to $25 per BOE over the life of each field, again depending on the field itself.

While these economic factors have wide ranges, our rate of return from these operations has generally been better than our rate of return on traditional oil and gas operations, and thus our tertiary operations have become our single most important focus area. While it is extremely difficult to accurately forecast future production, we do believe that our tertiary recovery operations provide significant long-term production growth potential at reasonable rates of return, with relatively low risk, and thus will be the backbone of our Company's growth for the foreseeable future. Although we believe that our plans and projections are reasonable and achievable, there could be delays or unforeseen problems in the future that could delay or affect the economics of our overall tertiary development program. We believe that such delays or price effects, if any, should only be temporary.

Financial Statement Impact of CO_2 Operations. Our increasing emphasis on CO_2 tertiary recovery projects has significantly impacted, and will continue to impact, our financial results and certain operating statistics. First, there is a significant delay between the initial capital expenditures on these fields and the resulting production increases, as 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 12 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 (see "Analysis of CO_2 Tertiary Recovery Operating Activities" below). Even after a field has proven reserves, there will usually be significant amounts of additional capital required to fully develop the field.

Second, tertiary projects may be more expensive to operate than other oil fields because of the cost of injecting and recycling the CO_2 (primarily due to the significant energy requirements to re-compress the CO_2 back into a near-liquid state for re-injection purposes). Since a significant portion of our operating costs vary along with commodity and electrical prices, these costs are highly variable and will increase in a high commodity price environment and decrease in a low price environment. As an example (as discussed above), during 2009 the cost of our CO_2 varied from $0.13 per Mcf to $0.21 per Mcf. 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 over 25% of the total operating costs for a tertiary operation. 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.

Analysis of CO_2 Tertiary Recovery Operating Activities. We currently have tertiary operations ongoing at all Phase 1 fields, at Soso, Martinville, Eucutta and Heidelberg Fields in Phase 2, Tinsley Field in Phase 3, Cranfield Field in Phase 4 and Delhi Field in Phase 5. We project that our oil production from our CO_2 operations will increase substantially over the next several years as we continue to expand this program by adding additional projects and phases. As of December 31, 2009, we had approximately 134.5 MMBbls of proved oil reserves related to tertiary operations (45.2 MMBbls in Phase 1, 44.6 MMBbls in Phase 2, 33.9 MMBbls in Phase 3 and 10.8 MMBbls in Phase 4) representing about 65% of our total corporate proved reserves, and have identified and estimate significant additional oil potential in other fields that we own in this region.

We added 17.6 MMBbls of tertiary-related proved oil reserves during 2009, primarily initial proven tertiary oil reserves at Cranfield Field in Phase 4, plus additional reserves at Tinsley, Heidelberg and Eucutta Fields. In order to recognize proved tertiary oil reserves, we must either have an oil production response to the CO_2 injections 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 and the timing of the production response.

Our average annual oil production from our CO_2 tertiary recovery activities has increased during the last few years, from 3,970 Bbls/d in 2002 to 24,343 Bbls/d during 2009 (26,307 Bbls/d during the fourth quarter of 2009). Tertiary oil production represented approximately 66% of our total corporate oil production during 2009 and approximately 50% of our total corporate production of both oil and natural gas during the same period on a BOE basis. We expect that this tertiary related oil production will continue to increase, although the increases are not always predictable or consistent. While we may have temporary fluctuation in oil production related to tertiary operations, this usually does not indicate any issue with the proved and potential oil reserves recoverable with CO_2, because the historical correlation between oil production and CO_2 injections remains high. A detailed discussion of each of our tertiary oil fields and the development of each is included on pages 11-14 under "Our Tertiary Oil Fields with Proved Tertiary Reserves." Following is a chart with our tertiary oil production by field for 2007, 2008 and 2009, and by quarter for 2009.

	Average Daily Production (BOE/d)						
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year Ended December 31,		
Tertiary Oil Field	2009	2009	2009	2009	2009	2008	2007
Phase 1:							
Brookhaven	3,451	3,466	3,397	3,350	3,416	2,826	2,048
Little Creek area	1,619	1,560	1,356	1,479	1,502	1,683	2,014
Mallalieu area	4,490	4,264	3,679	4,005	4,107	5,686	5,852
McComb area	2,246	2,429	2,473	2,412	2,391	1,901	1,912
Lockhart Crossing	607	698	882	1,025	804	186	—
Phase 2:							
Eucutta	3,813	4,145	4,068	3,912	3,985	3,109	1,646
Heidelberg	—	250	829	1,506	651	—	—
Martinville	1,118	951	720	724	877	865	709
Soso	2,705	2,589	2,813	3,224	2,834	2,111	586
Phase 3:							
Tinsley	2,390	3,402	3,558	3,942	3,328	1,010	—
Phase 4:							
Cranfield	144	338	572	728	448	—	—
Total tertiary oil production	22,583	24,092	24,347	26,307	24,343	19,377	14,767
Tertiary operating expense per Bbl	$ 20.48	$ 20.86	$ 23.14	$ 22.03	$ 21.67	$ 23.57	$ 19.77

Oil production from our tertiary operations increased to an average of 24,343 Bbls/d during 2009, a 26% increase over our 2008 tertiary production level of 19,377 Bbls/d. Tertiary oil production during the fourth quarter of 2009 averaged 26,307 Bbls/d, a 20% increase over the fourth quarter 2008 levels, and an 8% sequential increase from third quarter 2009 levels. These year-over-year increases are the result of production growth in response to continued expansion of the tertiary floods in our Tinsley, Soso, Eucutta and Brookhaven Fields, and to initial production response from Cranfield and Heidelberg Fields. We had our first production response from Cranfield Field during the first quarter of 2009 and our first response from Heidelberg Field in the second quarter of 2009, a little earlier than anticipated. Tinsley field has been one of our top performing tertiary oil fields, and production there is expected to increase as we continue to expand the flood. The declines at Mallalieu Field during the second and third quarters of 2009 were partially due to CO_2 recycle volumes exceeding the plant capacity, which limited production volumes. We have expanded the capacity of the facility, which expansion capacity became operational early in the fourth quarter of 2009. Although we received an initial increase in production following completion of the facility, we anticipate that production at Mallalieu Field will begin to decline again in the near future. The Delhi pipeline is complete, and we initiated CO_2 injections at Delhi Field (Phase 5) during November 2009. We currently anticipate tertiary production response at Delhi Field around mid-year 2010.

During 2009, operating costs for our tertiary properties averaged $21.67 per Bbl, lower than the prior year's average of $23.57 per Bbl. During the fourth quarter of 2009, the operating costs on our tertiary properties averaged $22.03 per Bbl as compared to $21.86 per Bbl in the fourth quarter of 2008 and $23.14 per Bbl during the third quarter of 2009. Our per barrel costs in 2009 are lower than in 2008 due primarily to the reduced cost of CO_2 in the current year period. On a per barrel basis, our cost of CO_2 decreased by $1.99 per Bbl, from $5.95 per Bbl in 2008 to $3.96 per Bbl in 2009, primarily due to the reduction in oil prices to which our CO_2 costs are partially tied. Our single highest cost for our tertiary operations is our cost for fuel and utilities, which averaged $5.76 per Bbl in 2009, $5.39 per Bbl in 2008 and $4.71 per Bbl in 2007, which has increased on a per barrel basis due to continued expansion of our tertiary floods. For any specific field, we expect our tertiary lease operating expense per BOE to be high initially, then decrease as production increases, ultimately leveling off until production begins to decline in the latter life of the field, when lease operating expense per BOE will again increase.

Through December 31, 2009, we have invested a total of $1.8 billion in tertiary fields (including allocated acquisition costs and amounts assigned to Goodwill) and have only $225.7 million in unrecovered net cash flow (revenue less operating expenses and capital expenditures). Of this total invested amount, approximately $487.4 million (27%) was spent on fields which have yet to have appreciable proved reserves at December 31, 2009 (i.e., fields for which significant incremental proved reserves are anticipated during 2010 and beyond). The proved oil reserves in our CO_2 fields have a PV-10 Value of $2.3 billion, using the calendar 2009 first-day-of-the-month 12-month unweighted average NYMEX pricing of $61.18 per Bbl. These amounts do not include the capital costs or related depreciation and amortization of our CO_2 producing properties, but do include CO_2 source field lease operating costs and transportation costs.

CO_2 Source Field and Tertiary Oil Field Related Capital Budget for 2010. Our current capital spending plans for 2010 include approximately $74 million to be spent in the Jackson Dome area with the intent to add CO_2 reserves and deliverability for future operations, approximately $365 million to be spent in development of our tertiary floods, and approximately $159 million to be spent for our CO_2 pipelines, making our combined CO_2 related expenditures over 90% of our $650 million 2010 capital budget.

Operating Results

As summarized in the "Overview" section above, and discussed in further detail below, our operating results increased from 2007 to 2008, but decreased from 2008 to 2009. The primary factors impacting our operating results were fluctuating commodity prices, changes in the fair value of our oil and natural gas derivative contracts, and increases and decreases in production, which are all explained in more detail below.

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, 2009	2008	2007
Operating results			
Net income (loss)	$ (75,156)	$ 388,396	$ 253,147
Net income (loss) per common share – basic	(0.30)	1.59	1.05
Net income (loss) per common share – diluted	(0.30)	1.54	1.00
Cash flow from operations	530,599	774,519	570,214
Average daily production volumes			
Bbls/d	36,951	31,436	27,925
Mcf/d	68,086	89,442	97,141
BOE/d[1]	48,299	46,343	44,115
Operating revenues			
Oil sales	$ 778,836	$1,066,917	$ 711,457
Natural gas sales	87,873	280,093	241,331
Total oil and natural gas sales	$ 866,709	$1,347,010	$ 952,788
Oil and natural gas derivative contracts[2]			
Cash receipt (payment) on settlement of derivative contracts	$ 146,734	$ (57,553)	$ 20,480
Non-cash fair value adjustment income (expense)	(382,960)	257,606	(39,077)
Total income (expense) from oil and natural gas derivative contracts	$ (236,226)	$ 200,053	$ (18,597)
Operating expenses			
Lease operating expenses	$ 326,132	$ 307,550	$ 230,932
Production taxes and marketing expenses[3]	42,484	63,752	49,091
Total production expenses	$ 368,616	$ 371,302	$ 280,023
Non-tertiary CO_2 operating margin			
CO_2 sales and transportation fees[4]	$ 13,422	$ 13,858	$ 13,630
CO_2 operating expenses	(4,649)	(4,216)	(4,214)
Non-tertiary CO_2 operating margin	$ 8,773	$ 9,642	$ 9,416
Unit prices – including impact of derivative settlements[2]			
Oil price per Bbl	$ 68.63	$ 90.04	$ 68.84
Natural gas price per Mcf	3.54	7.74	7.66
Unit prices – excluding impact of derivative settlements[2]			
Oil price per Bbl	$ 57.75	$ 92.73	$ 69.80
Natural gas price per Mcf	3.54	8.56	6.81
Oil and natural gas operating revenues and expenses per BOE[1]			
Oil and natural gas revenues	$ 49.16	$ 79.42	$ 59.17
Oil and natural gas lease operating expenses	$ 18.50	$ 18.13	$ 14.34
Oil and natural gas production taxes and marketing expense	2.41	3.76	3.05
Total oil and natural gas production expenses	$ 20.91	$ 21.89	$ 17.39

(1) Barrel of oil equivalent using the ratio of one barrel of oil to six Mcf of natural gas ("BOE").

(2) See also "Market Risk Management" below for information concerning the Company's derivative transactions.

(3) For 2009, 2008 and 2007, includes transportation expenses paid to Genesis of $7.9 million, $8.0 million and $6.0 million, respectively.

(4) For 2009, 2008 and 2007, includes deferred revenue of $4.2 million, $4.5 million, and $4.4 million, respectively, associated with volumetric production payments and transportation income of $5.5 million, $5.5 million and $5.2 million, respectively, both from Genesis.

Production: Average daily production by area for 2009, 2008 and 2007, and each of the quarters of 2009 is listed in the following table.

	Average Daily Production (BOE/d)						
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year Ended December 31,		
Operating Area	2009	2009	2009	2009	2009	2008	2007
Tertiary oil fields	22,583	24,092	24,347	26,307	24,343	19,377	14,767
Mississippi – non-CO_2 floods	11,904	10,043	8,931	8,914	9,937	11,897	12,479
Texas	17,063	16,088	7,579	8,035	12,154	13,214	10,074
Onshore Louisiana	708	885	699	679	743	624	5,542
Alabama and other	1,150	1,161	1,103	1,077	1,122	1,231	1,253
Total Company	53,408	52,269	42,659	45,012	48,299	46,343	44,115

As outlined in the above table, production increased 1,956 BOE/d (4%) between 2008 and 2009, and 2,228 BOE/d (5%) between 2007 and 2008. The increase from 2008 to 2009 is due primarily to a 26% increase in tertiary oil production and to the acquisition of Hastings Field, partially offset by the sale of our Barnett Shale properties and to decreases in our Mississippi – non-CO_2 floods. Excluding production from the Barnett Shale properties sold during 2009, production would have averaged 38,760 BOE/d during 2009 and 33,643 BOE/d during 2008, a 15% increase year-to-year. Our production increase between 2007 and 2008 was due to a 31% increase in tertiary oil production and production increases in the Barnett Shale, partially offset by the sale of our Louisiana natural gas properties and declines in our Mississippi – non-CO_2 floods. The increase in our tertiary oil production is discussed above under "Results of Operations – CO_2 Operations."

The acquisition of Hastings Field in February 2009 added 1,956 BOE/d during 2009 to our Texas area production. As discussed previously, we sold 60% of our interests in the Barnett Shale during June and July 2009, and sold our remaining 40% interest in these properties during December 2009.

Production in the Mississippi – non-tertiary operations decreased each of the last two years. Production in this area decreased 5% from 2007 to 2008, and further decreased 16% from 2008 to 2009. Most of this decrease is due to the expected gradual decline in Heidelberg Field due to depletion, although to a greater extent in 2009 due to the development of the Heidelberg CO_2 flood, which resulted in production being shut-in while portions of the field were converted to tertiary operations. When production commences from these CO_2 floods, these volumes are reported as tertiary production for Heidelberg Field. Also, production is lower in 2009 due to no drilling activity in the Selma Chalk. Our drilling activity in Sharon Field (natural gas) in the latter part of 2008 helped offset the declines in the first quarter of 2009, but production there has declined each of the last three quarters of 2009, as we did not drill any additional wells in 2009.

Our production during 2009 was 77% oil as compared to 68% during 2008 and 63% during 2007. This increase is due to the sale of our Louisiana natural gas assets during December 2007 and February 2008, the sale of our Barnett Shale properties during 2009, the acquisition of Hastings Field during February 2009, and to the increase in our tertiary operations each year. Pro forma for the sale of the Barnett assets and the Conroe acquisition, fourth quarter 2009 production would have been 91% oil.

Oil and Natural Gas Revenues: Fluctuating commodity prices resulted in an increase in our oil and natural gas revenues between 2007 and 2008, but a decline between 2008 and 2009. Our increasing production added to the revenue increase between 2007 and 2008, and partially offset the revenue decrease from commodity prices between 2008 and 2009. These changes in revenues, excluding any impact of our derivative contracts, are reflected in the following table.

	Year Ended December 31,			
	2009 vs. 2008		2008 vs. 2007	
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 in production	**$ 53,051**	**4%**	**$ 50,845**	**5%**
Increase (decrease) in commodity prices	**(533,352)**	**(40%)**	**343,377**	**36%**
Total increase (decrease) in revenues	**$(480,301)**	**(36%)**	**$394,222**	**41%**

Excluding any impact of our derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during 2009, 2008 and 2007:

	Year ended December 31,		
	2009	2008	2007
Net Realized Prices:			
Oil price per Bbl	**$ 57.75**	**$92.73**	**$69.80**
Natural gas price per Mcf	**3.54**	**8.56**	**6.81**
Price per BOE	**49.16**	**79.42**	**59.17**
NYMEX Differentials:			
Oil per Bbl	**$ (4.21)**	**$ (7.02)**	**$ (2.65)**
Natural gas per Mcf	**(0.63)**	**(0.33)**	**(0.28)**

Our Company-wide oil NYMEX differential improved during 2009 over our differential in 2008 primarily due to the overall decrease in oil prices during 2009. Likewise, our oil NYMEX differential widened during 2008 as compared to 2007, due to the overall increase in oil prices, with a peak in our differential during the second quarter of 2008, corresponding with the peak in oil prices. Our oil NYMEX differential was also positively impacted during 2009 due to reduced natural gas liquids production as a result of the sale of our Barnett Shale properties, which historically have a significantly higher differential to NYMEX

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 2009, 2008 and 2007.

In thousands	Non-Cash Fair Value Gain/(Loss) 2009	2008	2007	Cash Settlements Receipt/(Payment) 2009	2008	2007
Crude oil derivative contracts:						
First quarter	$ (95,861)	$ 2,638	$ (2,802)	$ 85,836	$ (7,392)	$ 126
Second quarter	(189,318)	(7,557)	(905)	42,002	(12,131)	(1,108)
Third quarter	(20,850)	22,652	(2,481)	18,527	(11,186)	(3,018)
Fourth quarter	(69,721)	242,156	(8,289)	369	(260)	(5,834)
December year-to-date	$(375,750)	$259,889	$(14,477)	$146,734	$(30,969)	$ (9,834)
Natural gas derivative contracts:						
First quarter	$ (10,490)	$ (41,371)	$(32,356)	$ —	$ (656)	$ 8,125
Second quarter	(5,473)	(22,666)	14,235	—	(16,463)	2,827
Third quarter	(1,434)	63,427	(2,960)	—	(12,886)	12,432
Fourth quarter	10,187	(1,673)	(3,519)	—	3,421	6,930
December year-to-date	$ (7,210)	$ (2,283)	$(24,600)	$ —	$(26,584)	$30,314
Total derivative contracts:						
First quarter	$(106,351)	$ (38,733)	$(35,158)	$ 85,836	$ (8,048)	$ 8,251
Second quarter	(194,791)	(30,223)	13,330	42,002	(28,594)	1,719
Third quarter	(22,284)	86,079	(5,441)	18,527	(24,072)	9,414
Fourth quarter	(59,534)	240,483	(11,808)	369	3,161	1,096
December year-to-date	$(382,960)	$257,606	$(39,077)	$146,734	$(57,553)	$20,480

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 changes in fair value of these contracts, as outlined above, are recognized currently in our income statement.

Production Expenses: Our lease operating expenses have increased each year on both a per BOE basis and in absolute dollars primarily as a result of (i) our increasing emphasis on tertiary operations and additional tertiary fields moving into the productive phase (see discussion of those expenses under "CO_2 Operations" above), (ii) the acquisition of Hastings Field in February 2009, which has a higher operating cost per BOE than most of our other properties, (iii) increased personnel and related costs, (iv) higher electrical costs to operate our properties due primarily to the expansion of our tertiary operations, (v) increasing lease payments due to incremental leasing of certain equipment in our tertiary operating facilities, and (vi) on a per BOE basis for 2009, the mid-year sale of our Barnett Shale natural gas properties, as these properties had a lower per unit operating cost.

Company-wide lease operating expense per BOE averaged $18.50 per BOE, $18.13 per BOE and $14.34 per BOE during 2009, 2008 and 2007, respectively. On a pro forma basis, after adjusting our operating results to remove the Barnett Shale production and operating expenses, Company-wide lease operating expenses would have been $21.94 per BOE during 2009, $23.02 per BOE during 2008 and $17.07 per BOE during 2007. Our tertiary operating costs, which have historically been higher than our company-wide operating costs, averaged $21.67 per BOE during 2009, $23.57 per BOE during 2008 and $19.77 per BOE during 2007 (see "Results of Operations – CO_2 Operations" for a more detailed discussion). As our tertiary operations become a larger percentage of our total operations, we expect that our operating costs on a per BOE basis will become closer to our tertiary operating costs, or higher as much of our conventional oil production, which is in decline, is at a higher per barrel cost than our tertiary operations. Costs of electricity and utilities to operate our properties have increased due primarily to the expansion of our tertiary operations. We expect our tertiary operating costs to partially correlate with oil prices, as the price we pay for CO_2 is partially tied to oil prices.

Production taxes and marketing expenses generally change in proportion to commodity prices and production volumes, and as such, decreased 33% between 2008 and 2009, correlating with the 36% decrease in total revenues between the two years and increased between 2007 and 2008 as a result of higher commodity prices. Transportation and plant processing fees were approximately $3.6 million lower in 2009 than 2008 primarily due to the sale of Barnett Shale properties in mid-2009, and were $8.4 million higher in 2008 than 2007 due to incremental Barnett Shale production and plant processing fees in 2008.

General and Administrative Expenses

During the last three years, general and administrative ("G&A") expenses have increased on both a gross basis and on a per BOE basis as outlined in the following table:

In thousands, except per BOE data and employees	Year Ended December 31, 2009	2008	2007
Gross cash G&A expense	**$143,886**	**$121,209**	**$103,334**
Employee stock-based compensation	**24,322**	**16,243**	**12,185**
Founder's retirement	**10,000**	—	—
Incentive compensation for Genesis management	**14,212**	—	—
Acquisition expenses	**8,921**	**527**	—
State franchise taxes	**4,703**	**3,415**	**2,915**
Operator labor and overhead recovery charges	**(76,044)**	**(68,556)**	**(59,145)**
Capitalized exploration and development costs	**(13,905)**	**(12,464)**	**(10,317)**
Net G&A expense	**$116,095**	**$ 60,374**	**$ 48,972**
G&A per BOE:			
Net cash G&A expense	**$ 3.27**	**$ 2.58**	**$ 2.30**
Net stock-based compensation	**1.16**	**0.75**	**0.56**
Founder's retirement	**0.57**	—	—
Incentive compensation for Genesis management	**0.81**	—	—
Acquisition expenses	**0.51**	**0.03**	—
State franchise tax	**0.27**	**0.20**	**0.18**
Net G&A expense	**$ 6.59**	**$ 3.56**	**$ 3.04**
Employees as of December 31	**830**	**797**	**686**

Gross cash G&A expenses increased $22.7 million, or 19% between 2008 and 2009, and $17.9 million, or 17%, between 2007 and 2008. The increases are primarily due to higher compensation and personnel related costs caused by an increase in the number of employees and higher wages, which we consider necessary in order to remain competitive in our industry. During 2008, we increased our employee count by 16%, and we further increased our employee count 4% during 2009, although our employee count was higher for part of 2009 before the sale of a portion of our Barnett Shale properties in mid-2009. Stock compensation expense reflected in gross G&A was $24.3 million during 2009, $16.2 million during 2008 and $12.2 million during 2007, due primarily to the increase in employees and changes in the mix of compensation awarded to employees. As discussed above in "Overview – Mid-Year Management Changes," we also expensed $10.0 million in the second quarter of 2009 related to a Founder's Retirement Agreement for Gareth Roberts, as he retired as CEO and President of the Company on June 30, 2009.

Also adding to the increase in net G&A expense for 2009 was a charge relating to incentive compensation awards for the management of Genesis of $14.2 million. As incentive compensation for Genesis' management, our former subsidiary which is the general partner of Genesis Energy, LP, awarded management the right to earn an interest in the incentive distributions we receive. These awards were subject to vesting over four years and achieving future levels of cash available before reserves on a per unit basis, among other conditions. As discussed above under "Overview – Sale of Interests in General Partner of Genesis Energy, L.P.", Denbury sold its interest in the general partner of Genesis on February 5, 2010. As such, the change in control provision of each member's compensation agreement was triggered and the awards were settled for $14.9 million in cash in February 2010. See also Note 15, "Subsequent Events" to the Consolidated Financial Statements for further information regarding these incentive compensation awards and the sale of our Class A interest in the Genesis general partner.

In addition to the increased compensation and other personnel related costs discussed above, an $8.4 million increase in acquisition related expenses also contributed to the increase in net G&A expense between 2008 and 2009. FASC "Business Combinations" topic requires that all transaction related costs (legal, accounting, due diligence, etc.) be expensed as incurred. As such, Denbury has recognized a total of $8.9 million of G&A expense in 2009 related primarily to transaction costs associated with the Encore acquisition.

The increase in gross G&A expense in each of the last three years was offset in part by an increase in operator overhead recovery charges. Our well operating agreements allow us, when we are the operator, to charge a well with a specified overhead rate during the drilling phase and also to charge a monthly fixed overhead rate for each producing well. As a result of additional operated wells from acquisitions, additional tertiary operations, drilling activity during the past year, and increased compensation expense, the amount we recovered as operator labor and overhead charges increased by 11% between 2008 and 2009, and 16% between 2007 and 2008. Capitalized exploration and development costs also increased each year, primarily due to additional personnel and increased compensation costs.

The net effect of the increases in gross G&A expenses, operator overhead recoveries and capitalized exploration costs was a 92% increase in net G&A expense between 2008 and 2009, and a 23% increase in net G&A expense between 2007 and 2008. On a per BOE basis, net G&A expense also increased each year, but at a lower percentage rate due to increased production, with an 85% increase in G&A per BOE in 2009 as compared 2008, and a 17% increase in 2008 as compared to 2007.

Interest and Financing Expenses

	Year Ended December 31,		
In thousands, except per BOE data and interest rates	2009	2008	2007
Cash interest expense	$ 108,629	$ 59,955	$ 49,205
Non-cash interest expense	7,397	1,802	2,010
Less: Capitalized interest	(68,596)	(29,161)	(20,385)
Interest expense	$ 47,430	$ 32,596	$ 30,830
Interest income and other	$ 2,362	$ 4,834	$ 6,642
Net cash interest expense and other income per BOE(1)	$ 2.14	$ 1.59	$ 1.43
Average debt outstanding	$1,265,142	$735,288	$672,376
Average interest rate(2)	8.6%	8.2%	7.3%

(1) Cash interest expense less capitalized interest less interest and other income on BOE basis.
(2) Includes commitment fees but excludes debt issue costs and amortization of discount and premium.

Interest expense increased $14.8 million, or 46%, between 2009 and 2008 and $1.8 million, or 6%, between 2007 and 2008. The increase in interest expense between 2008 and 2009 is due primarily to the February 2009 issuance of $420 million of 9.75% Senior Subordinated Notes due 2016, and to a full year of interest expense recognized during 2009 on the pipeline dropdown transactions with Genesis, as compared to only seven months of interest recognized on the dropdowns during 2008. This increase in interest expense between 2008 and 2009 was largely offset by a $39.4 million increase in capitalized interest, primarily relating to interest capitalized on our Green Pipeline currently under construction. The increase in interest expense between 2007 and 2008 was due primarily to the pipeline dropdown transactions with Genesis mid-2008, which were recorded as capital leases.

The increase in our average debt outstanding in 2009 as compared to 2008 is due the issuance of $420 million Senior Subordinated Notes due 2016, the pipeline dropdown transactions with Genesis, and to increased bank borrowings, primarily to fund our acquisitions.

Depletion, Depreciation and Amortization ("DD&A") and Full Cost Ceiling Test Write-down

	Year Ended December 31,		
In thousands, except per BOE data	2009	2008	2007
Depletion and depreciation of oil and natural gas properties	**$203,719**	**$192,791**	**$174,356**
Depletion and depreciation of CO_2 assets	**18,052**	**15,644**	**11,609**
Asset retirement obligations	**3,280**	**3,048**	**2,977**
Depreciation of other fixed assets	**13,272**	**10,309**	**6,958**
Total DD&A	**$238,323**	**$221,792**	**$195,900**
DD&A per BOE:			
Oil and natural gas properties	**$ 11.74**	**$ 11.55**	**$ 11.02**
CO_2 assets and other fixed assets	**1.78**	**1.53**	**1.15**
Total DD&A cost per BOE	**$ 13.52**	**$ 13.08**	**$ 12.17**
Full cost ceiling test write-down	**$ —**	**$226,000**	**$ —**

We adjust our DD&A rate each quarter for significant changes in our estimates of oil and natural gas reserves and costs, and thus our DD&A rate could change significantly in the future. Our DD&A rate for oil and natural gas properties on a per BOE basis increased slightly between 2008 and 2009 and increased approximately 5% between 2007 and 2008, due primarily to capital spending and increasing costs. Our proved reserves increased from 194.7 MMBOE as of December 31, 2007, to 250.5 MMBOE as of December 31, 2008, and decreased to 207.5 MMBOE as of December 31, 2009, due primarily to the sale of our Barnett Shale properties during 2009.

During 2009, we added approximately 48.8 MMBOE of proved reserves (before netting out 2009 production and property sales). The most significant additions were approximately 17.6 MMBOE related to our tertiary operations, 18.4 MMBOE related to the acquisition of Conroe Field, and 9.6 MMBOE related to the acquisition of Hastings Field. In the second quarter of 2009, we booked approximately 10.9 million barrels of incremental oil reserves related to our tertiary operations at Cranfield Field, as a result of the oil production response to the CO_2 injections in that field. Correspondingly, we moved approximately $82.4 million from unevaluated properties to the full cost pool relating to Cranfield Field, representing the acquisition costs and development expenditures incurred on the field prior to recognizing proved reserves

Our DD&A rate for our CO_2 and other fixed assets increased approximately 16% between 2008 and 2009, as a result of the Heidelberg CO_2 pipeline being placed into service during 2008, expansion of our corporate offices during 2008, and field office expansion during 2009. At December 31, 2009, we had $779.1 million of costs related to CO_2 pipelines under construction. These costs were not being depreciated at December 31, 2009. Depreciation of these pipelines will commence as each segment of pipeline is placed into service. Our DD&A rate for our CO_2 and other fixed assets increased in 2008 as compared to 2007, due primarily to the Heidelberg CO_2 pipeline being placed into service during 2008, drilling costs for additional CO_2 wells, and the expansion of our corporate office space in 2008.

As part of the requirements of the FASB guidance under the "Accounting for Asset Retirement Obligations" topic of the FASC, 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, with a corresponding capitalized amount. The liability is accreted each period, and the capitalized cost is depreciated over the useful life of the related asset. On an undiscounted basis, we estimated our retirement obligations at December 31, 2007 to be $100.6 million ($41.3 million present value), with an estimated salvage value of $67.3 million, and as of December 31, 2008, we estimated our retirement obligations to be $106.4 million ($45.1 million present value), with an estimated salvage value of $76.4 million, the increase related to 2008 activity and higher cost estimates due to the inflation in our industry, partially offset by a decrease in our obligation of approximately $9.5 million, ($9.3 million present value) related to the sale of most of our Louisiana natural gas properties in late 2007 and early 2008. As of December 31, 2009, we estimated our retirement obligations to be $134.5 million ($54.3 million present value), with an estimated salvage value of $81.4 million. The increase in our asset retirement obligations during 2009 was due to the acquisition of the Hastings and Conroe Fields, partially offset by the disposition of our Barnett Shale assets. DD&A is calculated on the increase in retirement obligations recorded as incremental oil and natural gas and CO_2 properties, net of its estimated salvage value. We also include the accretion of discount on the asset retirement obligation in our DD&A expense.

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. As a result of depressed oil and natural gas prices at December 31, 2008, we recorded our first full cost ceiling test write-down in a decade, resulting in expense of $226.0 million or $13.32 per BOE at December 31, 2008. The SEC adopted major revisions to its rules governing oil and gas company reporting requirements which were effective for us beginning on December 31, 2009. Under these new rules, the full cost ceiling value will be calculated using a 12-month average price based on the first day of every month during the period. We did not have a ceiling test write-down December 31, 2009. However, if oil prices were to decrease significantly in subsequent periods, we may be required to record additional 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.

Income Taxes

	Year Ended December 31,		
Amounts in thousands, except per BOE amounts and tax rates	2009	2008	2007
Current income tax expense	$ 4,611	$ 40,812	$ 30,074
Deferred income tax expense (benefit)	(51,644)	195,020	110,193
Total income tax expense (benefit)	$ (47,033)	$ 235,832	$ 140,267
Average income tax expense (benefit) per BOE	$ (2.67)	$ 13.90	$ 8.71
Effective tax rate	38.5%	37.8%	35.7%
Total net deferred tax liability	$(469,195)	$(522,234)	$(334,662)

Our income tax provision for each of the last three years has been based on an estimated statutory rate of approximately 38%. Our effective tax rate has generally been slightly lower than our estimated statutory rate due to the impact of certain items such as our domestic production activities deduction, offset in part by compensation arising from certain equity compensation that cannot be deducted for tax purposes in the same manner as book expense. Our 2009 effective tax rate was slightly higher, however, as compared to our statutory rate due to the recognition of net tax benefits related to the sale of our Barnett Shale assets. During 2009, 2008 and 2007, the current income tax expense represents our anticipated alternative minimum cash taxes that we cannot offset with enhanced oil recovery credits. As of December 31, 2009, we had an estimated $39 million of enhanced oil recovery credits to carry forward that can be utilized to reduce our current income taxes during 2010 or future years. These enhanced oil recovery credits do not begin to expire until 2024. Since the ability to earn additional enhanced oil recovery credits is based upon the level of oil prices, we would not currently expect to earn additional enhanced oil recovery credits unless oil prices were to decrease significantly from current levels.

In the second quarter of 2008, we obtained approval from the Internal Revenue Service ("IRS") to change our method of tax accounting for certain assets used in our tertiary oilfield recovery operations. Although the overall effects of this accounting change are under audit, we expect to receive tax refunds of approximately $10.6 million for tax years through 2007, along with other deferred tax benefits, and in the second quarter of 2008 we reduced our current income tax expense by approximately $19 million to adjust for the impact of this change through the first six months of 2008. The reduction in current income tax expense has been offset by a corresponding increase in deferred income tax expense of approximately the same amount. Although this change is not expected to have a significant impact on the Company's overall tax rate, it is anticipated that it could defer the amount of cash taxes the Company might otherwise pay over the next several years. The current administration in Washington D.C. is attempting to remove many tax incentives for the oil and gas industry. Those items that would have the most significant impact on us would include the loss of the domestic manufacturing deduction as well as the repeal of the immediate expensing of intangible drilling costs and tertiary injectant costs. It is uncertain whether or not the current administration will be successful in changing the laws, but if they were successful, it would likely increase the amount of cash taxes that we pay.

Per BOE Data

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

Per BOE data	Year Ended December 31, 2009	2008	2007
Oil and natural gas revenues	$ 49.16	$ 79.42	$ 59.17
Gain (loss) on settlements of derivative contracts	8.32	(3.40)	1.27
Lease operating expenses	(18.50)	(18.13)	(14.34)
Production taxes and marketing expenses	(2.41)	(3.76)	(3.05)
Production netback	36.57	54.13	43.05
Non-tertiary CO_2 operating margin	0.50	0.57	0.58
General and administrative expenses	(6.59)	(3.56)	(3.04)
Net cash interest expense and other income	(2.14)	(1.59)	(1.43)
Abandoned acquisition costs	—	(1.80)	—
Current income taxes and other	2.30	(1.78)	(1.37)
Changes in assets and liabilities relating to operations	(0.54)	(0.31)	(2.38)
Cash flow from operations	30.10	45.66	35.41
DD&A	(13.52)	(13.08)	(12.17)
Write-down of oil and natural gas properties	—	(13.32)	—
Deferred income taxes	2.93	(11.50)	(6.84)
Non-cash commodity derivative adjustments	(21.72)	15.19	(2.43)
Changes in assets and liabilities and other non-cash items	(2.05)	(0.05)	1.75
Net income (loss)	$ (4.26)	$ 22.90	$ 15.72

MARKET RISK MANAGEMENT

Debt

We finance some of our acquisitions and other expenditures with fixed and variable rate debt. These debt agreements expose us to market risk related to changes in interest rates. We had $125 million of bank debt outstanding as of December 31, 2009. The carrying value of our bank debt is approximately fair value based on the fact that it is subject to short-term floating interest rates that approximate the rates available to us for those periods. We adjusted the estimated fair value measurements of our bank debt at December 31, 2009, for estimated nonperformance risk. This estimated nonperformance risk totaled approximately $2.5 million and was determined utilizing industry credit default swaps. None of our existing debt has any triggers or covenants regarding our debt ratings with rating agencies, although under the NEJD financing lease with Genesis (see Note 3, "Related Party Transactions — Genesis" to our Consolidated Balance Sheets) in the event of significant downgrades of our corporate credit rating by the rating agencies, Genesis can require certain credit enhancements from us, and possibly other remedies under the lease. The fair value of the subordinated debt is based on quoted market prices. The following table presents the carrying and fair values of our debt, along with average interest rates at December 31, 2009.

	Expected Maturity Dates					
In thousands	2011	2013	2015	2016	Carrying Value	Fair Value
Variable rate debt:						
Bank debt (weighted average interest rate of 1.49% at December 31, 2009)	$125,000	$ —	$ —	$ —	$125,000	$122,500
Fixed rate debt:						
7.5% subordinated debt due 2013 (fixed rate of 7.5%)	—	225,000	—	—	224,369	226,125
7.5% subordinated debt due 2015 (fixed rate of 7.5%)	—	—	300,000	—	300,513	299,250
9.75% subordinated debt due 2016 (fixed rate of 9.75%)	—	—	—	426,350	399,926	455,129

Oil and Natural Gas Derivative Contracts

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. In early 2009, we began to employ a strategy to hedge a portion of our production looking out 12 to 15 months from each 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. However, as a result of our plan to acquire Encore and the potentially higher debt levels necessary to finance that merger, we entered into costless collars in early November 2009, to hedge a significant portion of our production through 2011. See Note 10 to the Consolidated Financial Statements for details regarding our derivative contracts.

All of the mark-to-market valuations used for our oil and natural gas derivatives are provided by external sources and are based on prices that are actively quoted. 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 derivative contracts are with parties that are lenders under our Senior Bank Loan. We have included an estimate of nonperformance risk in the fair value measurement of our oil and natural gas derivative contracts. We have measured nonperformance risk based upon credit default swaps or credit spreads. At December 31, 2009 and December 31, 2008, the fair value of our oil and natural gas derivative contracts was reduced by $0.8 million and $3.7 million, respectively, for estimated nonperformance risk.

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. Information regarding our current derivative contract positions and results of our historical derivative activity is included in Note 10 to the Consolidated Financial Statements.

At December 31, 2009, our derivative contracts were recorded at their fair value, which was a net liability of approximately $128.7 million, a significant change from the $249.7 million fair value asset recorded at December 31, 2008. This change is primarily related to the expiration of oil derivative contracts during 2009, and to the oil and natural gas futures prices as of December 31, 2009, in relation to the new commodity derivative contracts we entered into during 2009 for 2010 and 2011.

Commodity Derivative Sensitivity Analysis

Based on NYMEX crude oil and natural gas futures prices as of December 31, 2009, and assuming both a 10% increase and decrease thereon, we would expect to make or receive payments on our crude oil and natural gas derivative contracts as seen in the following table:

In thousands	Crude Oil Derivative Contracts Receipt/ (Payment)	Natural Gas Derivative Contracts Receipt/ (Payment)
Based on:		
NYMEX futures prices as of December 31, 2009	**$ (85,193)**	**$ (2,813)**
10% increase in prices	**(148,189)**	**(17,310)**
10% decrease in prices	**(45,653)**	**11,692**

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 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 Reserves

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 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 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 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 FASC hedge accounting topic, 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 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 natural 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 the report, the subjective decisions and variances in available data for various fields make these estimates generally less precise than other estimates included in our financial statement disclosures. Over the last four years, Denbury's annual revisions to its reserve estimates have averaged approximately 1.9% of the previous year's estimates and have been both positive and negative.

Changes in commodity prices also affect our reserve quantities. Between 2006 and 2007, the change to reserve quantities related to commodity prices was relatively small as prices were relatively high each year-end; however, at December 31, 2008, the lower commodity prices lowered our proved reserves by 13.8 MMBOE. Between 2008 and

2009, commodity prices increased, resulting in an increase in our proved reserves of 4.2 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 2009 DD&A rate from $14.77 per BOE to approximately $14.19 per BOE, and a 5% decrease in our proved reserve quantities would have increased our DD&A rate to approximately $15.42 per BOE. Also, reserve quantities and their ultimate values are the primary factors in determining the borrowing base under our bank credit facility and are determined solely by our banks.

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. We did not have a full cost pool ceiling test write-down in 2007 or 2009. However, during 2008, commodity prices were volatile, with oil NYMEX prices moving from $95.98 per Bbl at December 31, 2007, to $140.00 per Bbl at June 30, 2008, then down to $44.60 per Bbl at December 31, 2008. Likewise, natural gas NYMEX prices went from $7.48 per Mcf as of December 31, 2007, to $13.35 per Mcf at June 30, 2008, and down to $5.62 per Mcf as of December 31, 2008. Because of the 54% decrease in NYMEX oil price and 25% decrease in NYMEX natural gas price between year-end 2007 and year-end 2008, we recognized a full cost pool ceiling test write-down during 2008 of $226.0 million, or $13.32 per BOE. Commodity prices increased throughout 2009, ending the year with NYMEX oil prices at $79.36 per barrel, and NYMEX natural gas prices at $5.57 per Mcf. Commodity prices have historically been volatile and are expected to be in the future. If oil and natural gas should again decrease, we may be required to record additional write-downs due to the full cost ceiling test. Beginning in the fourth quarter of 2009, the full cost accounting rules require the use of 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 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 there is a production response to the injected CO_2, 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 costs of production, transportation and acquisition, and to pay royalties.

Prior to January 1, 2008, we expensed currently all costs associated with injecting CO_2 that we used in our tertiary recovery operations, even though some of these costs were incurred prior to any tertiary related oil production. Commencing January 1, 2008, we began capitalizing, 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. Had the new method of accounting for tertiary injection costs been used in periods prior to January 1, 2008, the effect on our financial statements would have been immaterial for all periods presented. During 2008 and 2009, we capitalized $10.4 million and $8.0 million, respectively, of tertiary injection costs associated with our tertiary projects that we would have previously expensed.

Income Taxes

We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Our federal and state income tax returns are generally not prepared or filed before the consolidated financial statements are prepared; therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits, and net operating loss carryforwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we file our income tax returns. Further, we must assess the likelihood that we will be able to recover or utilize our deferred tax assets (primarily our enhanced oil recovery credits and state loss carryforwards). If recovery is not likely, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover, which would result in an increase to our income tax expense. As of December 31, 2009, we believe that all of our deferred tax assets recorded on our Consolidated Balance Sheet will ultimately be recovered. If our estimates and judgments change regarding our ability to utilize our deferred tax assets, our tax provision would increase in the period it is determined that recovery is not likely. A 1% increase in our effective tax rate would have increased our calculated income tax expense (benefit) by approximately $(1.2) million, $6.2 million, and $3.9 million for the years ended December 31, 2009, 2008 and 2007, respectively. See Note 7 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 11 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. FASC "Business Combinations" topic defines the acquisition date as the date on which the acquirer obtains control of the acquiree, which is usually a date different than the date the economics of the acquisition are established between the acquirer and the acquiree. 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 property, plant and equipment and identifiable intangible assets. This is even more difficult due to the nature of our core business, enhanced oil recovery operations. In order to appropriately apply the FASC standard, we must estimate what value a third party market participant would place on the acquired property. This is extremely difficult as we are one of few industry entities that perform EOR operations and in our current operating area, the Gulf Coast, we are the only entity that we know of that currently has a significant source of CO_2 available to them. Therefore, it is very subjective as to what value another entity would place on the potential barrels recoverable with CO_2, which impacts our allocation of the purchase price to goodwill, unevaluated properties and proved properties. Although we find that this standard is difficult to apply in our circumstance, we use all available information to make these fair value determinations and, for certain acquisitions, engage third-party consultants for assistance.

The fair values used to allocate the purchase price of an acquisition are often estimated using the expected present value of future cash flows method, which requires us to project related future cash inflows and outflows and apply an appropriate discount rate. The estimates used in determining fair values are based on assumptions believed to be reasonable but which 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. The pending Merger, if approved, will likely result in a significant increase to our existing goodwill.

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.

Fair value calculated for the purpose of testing for impairment of our goodwill is estimated using the expected present value of future cash flows method and comparative market prices when appropriate. A significant amount of judgment is involved 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 which we believe to be reasonable. However, actual results may differ from those projections.

Oil and Natural Gas Derivative Contracts

We enter into oil and natural gas derivative contracts to mitigate our exposure to commodity price risk associated with future oil and natural gas production. These contracts have historically consisted of options, in the form of price floors or collars, and fixed price swaps. We do not designate these derivative commodity contracts as hedge instruments for accounting purposes under the FASC hedge accounting topic. This means that any changes in the future fair value of these derivative contracts will be charged to earnings on a quarterly basis instead of charging the effective portion to other comprehensive income and the balance to earnings. While we may experience more volatility in our net income than if we were to apply hedge accounting treatment as permitted by the FASC hedge accounting 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 2009, 2008 and 2007, we recognized expense (income) of $383.0 million, $(257.6) million, and $39.1 million, respectively, related to non-cash changes in the fair market value of our derivative contracts.

Stock Compensation Plans

The FASB guidance under the "Share-Based Payment" topic of the FASC, requires that we recognize the cost of employee services received in exchange for awards of equity instruments, based on the grant date fair value of those awards, in the financial statements. We estimate the fair value of stock option or stock appreciation right ("SAR") awards on the date of grant using the Black-Scholes option pricing model. The Black-Scholes option valuation model requires the input of somewhat subjective assumptions, including expected stock price volatility and expected term. Other assumptions required for estimating fair value with the Black-Scholes model are the expected risk-free interest rate and expected dividend yield of the Company's stock. The risk-free interest rates used are the U.S. Treasury yield for bonds matching the expected term of the option on the date of grant. Our dividend yield is zero, as Denbury does not pay a dividend. We utilize historical experience in arriving at our assumptions for volatility and expected term inputs.

We recognize the stock-based compensation expense on a straight-line basis over the requisite service period for the entire award. The expense we recognize is net of estimated forfeitures. We estimate our forfeiture rate based on prior experience and true it up for actual results as the awards vest. As of December 31, 2009, there was $18.8 million of total compensation cost to be recognized in future periods related to non-vested stock options and SARs. The cost is expected to be recognized over a weighted-average period of 2.5 years.

Asset Retirement Obligations

We have significant obligations related to the plugging and abandonment of our oil, natural gas and CO_2 wells, the removal of equipment and facilities from leased acreage, and land restoration. The FASC asset retirement topic requires that we estimate the future cost of this obligation, discount it to its present value, and record a corresponding asset and liability in our Consolidated Balance Sheets. The values ultimately derived are based on many significant estimates, including the ultimate expected cost of the obligation, the expected future date of the required cash payment, and interest and inflation rates. Revisions to these estimates may be required based on changes to cost estimates, the timing of settlement, and changes in legal requirements. Any such changes that result in upward or downward revisions in the estimated obligation will result in an adjustment to the related capitalized asset and corresponding liability on a prospective basis and an adjustment in our DD&A expense in future periods. See Note 4 to our Consolidated Financial Statements for further discussion regarding our asset retirement obligations.

USE OF ESTIMATES

The preparation of financial statements requires us to make other estimates and assumptions that affect the reported amounts of certain assets, liabilities, revenues and expenses during each reporting period. We believe that our estimates and assumptions are reasonable and reliable, and believe that the ultimate actual results will not differ significantly from those reported; however, such estimates and assumptions are subject to a number of risks and uncertainties, and such risks and uncertainties could cause the actual results to differ materially from our estimates.

RECENT ACCOUNTING PRONOUNCEMENTS

Transfers of Financial Assets. In June 2009, the FASB issued guidance related to the accounting for transfers of financial assets. The guidance removes the concept of a qualifying special-purpose entity ("QSPE") from FASC topic, "Transfers and Servicing", creates a new unit of account definition that must be met for transfers of portions of financial assets to be eligible for sale accounting, clarifies the de-recognition criteria for a transfer to be accounted for as a sale, changes the amount of recognized gains or losses on the transfer of financial assets accounted for as a sale when beneficial interests are received by the transferor and introduces new disclosure requirements. The new guidance is effective for us beginning January 1, 2010. The adoption did not have a material impact on our financial condition or results of operations.

Consolidation of Variable Interest Entities. In June 2009, the FASB issued guidance to eliminate the exemption in the "Consolidation" topic of the FASC for QSPEs, introduce a new approach for determining who should consolidate a variable interest entity and change the requirement as to when it is necessary to reassess who should consolidate a variable interest entity. We adopted the standard on January 1, 2010. The adoption did not have a material impact on our financial condition or results of operations.

Fair Value Disclosures. In January 2010, the FASB issued guidance in the "Fair Value Measurements and Disclosures" topic of the FASC to enhance disclosures surrounding the transfers of assets in and out of level 1 and level 2, to present more detail surrounding asset activity for level 3 assets and to clarify existing disclosure requirements. The new guidance is effective for the Company beginning January 1, 2010, and will not have any impact on our financial position or statement of operations.

FORWARD-LOOKING INFORMATION

The statements contained in this Annual Report on Form 10-K that are not historical facts, including, but not limited to, statements found in this 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, and are subject to the impact of the Merger with Encore on the results of operations and financial condition of the combined company. Such forward-looking statements may be or may concern, among other things, forecasted capital expenditures, drilling activity or methods, acquisition plans and proposals and dispositions, development activities, cost savings, capital budgets, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO_2 reserves, potential reserves from tertiary operations, 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, 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 the Company's financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by or on behalf of the Company. Among the factors that could cause actual results to differ materially are: fluctuations of the prices received or demand for the Company's oil and natural gas; unexpected difficulties in integrating the operations of Denbury and Encore; 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 which are otherwise discussed in this annual report, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in the Company's other public reports, filings and public statements.

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," appearing on pages 60 through 61.

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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, 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, 2009, 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 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.

As discussed in Note 1 and Note 16 to the Consolidated Financial Statements, the Company changed the manner in which it estimates the quantities of oil and natural gas reserves in 2009.

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

March 1, 2010

CONSOLIDATED BALANCE SHEETS

In thousands, except shares	December 31, 2009	December 31, 2008
Assets		
Current assets		
Cash and cash equivalents	$ 20,591	$ 17,069
Accrued production receivable	120,667	67,805
Trade and other receivables, net of allowance of $414 and $377	67,874	80,579
Derivative assets	309	249,746
Current deferred tax assets	46,321	—
Total current assets	255,762	415,199
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved	3,595,726	3,386,606
Unevaluated	320,356	235,403
CO_2 properties, equipment and pipelines	1,529,781	899,542
Other	82,537	70,328
Less accumulated depletion, depreciation and impairment	(1,825,528)	(1,589,682)
Net property and equipment	3,702,872	3,002,197
Deposits on property under option or contract	—	48,917
Other assets	66,810	43,357
Goodwill	169,517	—
Investment in Genesis	75,017	80,004
Total assets	$ 4,269,978	$ 3,589,674
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 169,874	$ 202,633
Oil and gas production payable	90,218	85,833
Derivative liabilities	124,320	—
Deferred revenue – Genesis	4,070	4,070
Deferred tax liability	—	89,024
Current maturities of long-term debt	5,308	4,507
Total current liabilities	393,790	386,067
Long-term liabilities		
Long-term debt – Genesis	249,762	251,047
Long-term debt	1,051,306	601,720
Asset retirement obligations	53,251	43,352
Deferred revenue – Genesis	15,749	19,957
Deferred tax liability	515,516	433,210
Derivative liabilities	5,239	—
Other	13,128	14,253
Total long-term liabilities	1,903,951	1,363,539
Commitments and contingencies (Note 12)		
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; 261,929,292 and 248,005,874 shares issued at December 31, 2009 and 2008, respectively	262	248
Paid-in capital in excess of par	910,540	707,702
Retained earnings	1,064,419	1,139,575
Accumulated other comprehensive loss	(557)	(627)
Treasury stock, at cost, 156,284 and 446,287 shares at December 31, 2009 and 2008, respectively	(2,427)	(6,830)
Total stockholders' equity	1,972,237	1,840,068
Total liabilities and stockholders' equity	$ 4,269,978	$ 3,589,674

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF OPERATIONS

In thousands, except per share data	Year ended December 31, 2009	2008	2007
Revenues and other income			
Oil, natural gas and related product sales	$ 866,709	$1,347,010	$952,788
CO_2 sales and transportation fees	13,422	13,858	13,630
Interest income and other	2,362	4,834	6,642
Total revenues	882,493	1,365,702	973,060
Expenses			
Lease operating expenses	326,132	307,550	230,932
Production taxes and marketing expenses	34,580	55,770	43,130
Transportation expense – Genesis	7,904	7,982	5,961
CO_2 operating expenses	4,649	4,216	4,214
General and administrative	116,095	60,374	48,972
Interest, net of amounts capitalized of $68,596, $29,161, and $20,385, respectively	47,430	32,596	30,830
Depletion, depreciation and amortization	238,323	221,792	195,900
Commodity derivative expense (income)	236,226	(200,053)	18,597
Abandoned acquisition costs	—	30,601	—
Write-down of oil and natural gas properties	—	226,000	—
Total expenses	1,011,339	746,828	578,536
Equity in net income (loss) of Genesis	6,657	5,354	(1,110)
Income (loss) before income taxes	(122,189)	624,228	393,414
Income tax provision (benefit)			
Current income taxes	4,611	40,812	30,074
Deferred income taxes	(51,644)	195,020	110,193
Net income (loss)	$ (75,156)	$ 388,396	$253,147
Net income (loss) per common share – basic	$ (0.30)	$ 1.59	$ 1.05
Net income (loss) per common share – diluted	$ (0.30)	$ 1.54	$ 1.00
Weighted average common shares outstanding			
Basic	246,917	243,935	240,065
Diluted	246,917	252,530	252,101

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

In thousands	Year Ended December 31, 2009	2008	2007
Cash flow from operating activities:			
Net income (loss)	$ (75,156)	$ 388,396	$ 253,147
Adjustments needed to reconcile to net cash flow provided by operations:			
Depletion, depreciation and amortization	238,323	221,792	195,900
Write-down of oil and natural gas properties	—	226,000	—
Deferred income taxes	(51,644)	195,020	110,193
Deferred revenue – Genesis	(4,208)	(4,466)	(4,419)
Stock-based compensation	35,581	14,068	10,595
Non-cash fair value derivative adjustments	383,072	(257,502)	38,952
Founder's retirement compensation	6,350	—	—
Other	7,719	(3,499)	4,149
Changes in assets and liabilities related to operations:			
Accrued production receivable	(52,863)	68,479	(63,886)
Trade and other receivables	12,548	(58,236)	(10,409)
Derivative assets	—	(15,471)	—
Other assets	(426)	348	(819)
Accounts payable and accrued liabilities	25,673	254	1,576
Oil and gas production payable	4,385	1,683	31,906
Other liabilities	1,245	(2,347)	3,329
Net cash provided by operating activities	530,599	774,519	570,214
Cash flow used for investing activities:			
Oil and natural gas capital expenditures	(343,351)	(587,968)	(621,187)
Acquisitions of oil and natural gas properties	(452,795)	(31,367)	(49,077)
CO_2 capital expenditures, including pipelines	(666,372)	(407,103)	(164,075)
Investment in Genesis	4,975	6,623	(47,738)
Purchases of other assets	(13,591)	(23,799)	(13,672)
Proceeds from sales of oil and gas properties and equipment	516,814	51,684	142,667
Other	(15,394)	(2,729)	(9,431)
Net cash used for investing activities	(969,714)	(994,659)	(762,513)
Cash flow from financing activities:			
Bank repayments	(856,000)	(222,000)	(265,000)
Bank borrowings	906,000	147,000	281,000
Income tax benefit from equity awards	3,913	19,665	19,181
Issuance of subordinated debt	389,827	—	150,750
Pipeline financing – Genesis	369	225,252	—
Issuance of common stock	12,991	13,972	18,222
Costs of debt financing	(10,080)	(2,288)	(1,988)
Other	(4,383)	(4,499)	(3,632)
Net cash provided by financing activities	442,637	177,102	198,533
Net increase (decrease) in cash and cash equivalents	3,522	(43,038)	6,234
Cash and cash equivalents at beginning of year	17,069	60,107	53,873
Cash and cash equivalents at end of year	$ 20,591	$ 17,069	$ 60,107

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

Dollar amounts in thousands	Common Stock ($.001 Par Value) Shares	Common Stock Amount	Paid-In Capital in Excess of Par	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock (at cost) Shares	Treasury Stock Amount	Total Stockholders' Equity
Balance – December 31, 2006	120,506,815	$121	$616,046	$ 498,032	$ —	370,327	$(8,140)	$1,106,059
Repurchase of common stock	—	—	—	—	—	74,130	(2,960)	(2,960)
Issued pursuant to employee stock purchase plan	—	—	2,099	—	—	(149,360)	2,947	5,046
Issued pursuant to employee stock option plan	2,071,940	2	13,174	—	—	—	—	13,176
Issued pursuant to directors' compensation plan	3,981	—	136	—	—	—	—	136
Two-for-one stock split	122,626,451	122	(122)	—	—	342,698	—	—
Restricted stock grants	198,354	—	—	—	—	—	—	—
Restricted stock grants – forfeited	(20,590)	—	—	—	—	—	—	—
Stock based compensation	—	—	12,184	—	—	—	—	12,184
Income tax benefit from equity awards	—	—	19,181	—	—	—	—	19,181
Derivative contracts, net	—	—	—	—	(1,591)	—	—	(1,591)
Net income	—	—	—	253,147	—	—	—	253,147
Balance – December 31, 2007	245,386,951	245	662,698	751,179	(1,591)	637,795	(8,153)	1,404,378
Repurchase of common stock	—	—	—	—	—	155,297	(3,762)	(3,762)
Issued pursuant to employee stock purchase plan	—	—	1,176	—	—	(346,805)	5,085	6,261
Issued pursuant to employee stock option plan	2,578,563	3	7,708	—	—	—	—	7,711
Issued pursuant to directors' compensation plan	12,753	—	212	—	—	—	—	212
Restricted stock grants	278,973	—	—	—	—	—	—	—
Restricted stock grants – forfeited	(251,366)	—	—	—	—	—	—	—
Stock based compensation	—	—	16,243	—	—	—	—	16,243
Income tax benefit from equity awards	—	—	19,665	—	—	—	—	19,665
Derivative contracts, net	—	—	—	—	964	—	—	964
Net income	—	—	—	388,396	—	—	—	388,396
Balance – December 31, 2008	248,005,874	248	707,702	$ 1,139,575	(627)	446,287	(6,830)	1,840,068
Repurchase of common stock	—	—	—	—	—	194,943	(3,014)	(3,014)
Issued pursuant to employee stock purchase plan	—	—	(81)	—	—	(484,946)	7,417	7,336
Issued pursuant to employee stock option plan	1,312,714	2	5,651	—	—	—	—	5,653
Issued pursuant to directors' compensation plan	21,658	—	322	—	—	—	—	322
Issued pursuant to Conroe Field acquisition	11,620,000	12	168,711	—	—	—	—	168,723
Restricted stock grants	1,032,895	—	—	—	—	—	—	—
Restricted stock grants – forfeited	(63,849)	—	—	—	—	—	—	—
Stock based compensation	—	—	24,322	—	—	—	—	24,322
Income tax benefit from equity awards	—	—	3,913	—	—	—	—	3,913
Derivative contracts, net	—	—	—	—	70	—	—	70
Net loss	—	—	—	(75,156)	—	—	—	(75,156)
Balance – December 31, 2009	261,929,292	$262	$910,540	$ 1,064,419	$ (557)	156,284	$(2,427)	$1,972,237

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE OPERATIONS

	Year Ended December 31,		
In thousands	2009	2008	2007
Net income (loss)	**$(75,156)**	**$388,396**	**$253,147**
Other comprehensive income (loss), net of income tax:			
Change in fair value of interest rate lock contracts designated as a hedge, net of taxes of $—, $49 and $1,017, respectively	**—**	**12**	**(1,591)**
Interest rate lock derivative contracts reclassified to income, net of taxes of $43, $583 and $—, respectively	**70**	**952**	**—**
Comprehensive income (loss)	**$(75,086)**	**$389,360**	**$251,556**

See accompanying Notes to Consolidated Financial Statements.

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION AND NATURE OF OPERATIONS

Denbury Resources Inc. is a Delaware corporation, organized under *Delaware General Corporation Law,* engaged in the acquisition, development, operation and exploration of oil and natural gas properties. We have one primary business segment, which is the exploration, development and production of oil and natural gas in the U.S. Gulf Coast region. We also own the rights to a natural source of carbon dioxide ("CO_2") reserves that we use for injection in our tertiary oil recovery operations. We also sell some of the CO_2 we produce to Genesis Energy, L.P. ("Genesis") (see Note 3) and to third party industrial users.

PRINCIPLES OF REPORTING AND CONSOLIDATION

The consolidated financial statements herein have been prepared in accordance with generally accepted accounting principles ("GAAP") and include the accounts of Denbury and its subsidiaries, all of which are wholly owned. A former Denbury subsidiary, Genesis Energy, LLC is the general partner of, and together with Denbury's other subsidiaries, owned an aggregate 12% interest in Genesis at December 31, 2009, a publicly traded master limited partnership. We accounted for our 12% ownership interest in Genesis under the equity method of accounting. Even though we had significant influence over the limited partnership in our role as general partner, because our control was limited by the Genesis limited partnership agreement we did not consolidate Genesis. On February 5, 2010, we sold our interest in Genesis Energy, LLC, but we still retain an approximate 10% limited partner interest in Genesis (for which a resale registration statement was filed in January 2010) in which we continue to account for under the equity method of accounting. See Note 3, "Related Party Transactions – Genesis" for more information regarding our related party transactions with Genesis and see Note 15, "Subsequent Events" for more information about the sale of our general partnership interest. All material intercompany balances and transactions have been eliminated. We have evaluated our consolidation of variable interest entities in accordance with "Consolidation" topic of the Financial Accounting Standards Board Codification ("FASC"), and have concluded that we do not have any variable interest entities that would require consolidation.

STOCK SPLIT

On November 19, 2007, stockholders of Denbury Resources Inc. approved an amendment to our Restated Certificate of Incorporation to increase the number of shares of our authorized common stock from 250,000,000 shares to 600,000,000 shares and to split our common stock on a 2-for-1 basis. Stockholders of record on December 5, 2007, received one additional share of Denbury common stock for each share of common stock held at that time.

Information pertaining to shares and earnings per share has been retroactively adjusted in the accompanying financial statements and related notes thereto to reflect the stock split, except for the share amounts included on our Consolidated Balance Sheets and Consolidated Statements of Changes in Stockholders' Equity, which reflect the actual shares outstanding at each period end.

OIL AND NATURAL GAS OPERATIONS

Capitalized Costs. We follow the full cost method of accounting for oil and natural gas properties. Under this method, all costs related to acquisitions, exploration and development of oil and natural gas reserves are capitalized and accumulated in a single cost center representing our activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells, capitalized interest on qualifying projects, and general and administrative expenses directly related to exploration and development activities, and do not include any costs related to production, general corporate overhead or similar activities. 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 is recognized.

Depletion and Depreciation. The costs capitalized, including production equipment and future development costs, are depleted or depreciated on 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 based upon the relative energy content, which is six thousand 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 $13.39 in 2009, $12.54 in 2008 and $11.60 in 2007.

Asset Retirement Obligations. In general, our future asset retirement obligations relate to future costs associated with plugging and abandonment of our oil, natural gas and CO_2 wells, removal of equipment and facilities from leased acreage, and returning such 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. See Note 4 for more information regarding our asset retirement obligations.

Ceiling Test. The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized cost or the cost center ceiling. The cost center ceiling is defined as the sum of (i) the present value of estimated future net revenues from proved reserves before future abandonment costs (discounted at 10%), based on unescalated period-end oil and natural gas prices during 2007, 2008 and for the first three quarters of 2009; and beginning in the fourth quarter of 2009, the average first-day-of-the-month oil and natural gas price for each month during the 12-month period ended December 31, 2009; (ii) plus the cost of properties not being amortized; (iii) plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; (iv) less related income tax effects. We include that portion of net capitalized costs of CO_2 assets and CO_2 pipelines that are required for our current proved tertiary reserves in the net capitalized costs subject to the ceiling test. The cost center ceiling test is prepared quarterly.

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

Proved Reserves. See Note 16, "Supplemental Oil and Natural Gas Disclosures (Unaudited)" for information on our proved oil and natural gas reserves and the basis on which they are recorded.

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 there is a production response to the injected CO_2, 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 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 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 any previously deferred unevaluated development costs will become subject to depletion upon recognition of proved tertiary reserves. During the years ended December 31, 2009 and 2008, we capitalized $8.0 million and $10.4 million, respectively, of tertiary injection costs associated with our tertiary projects that were in the development phase.

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. Estimated useful lives are generally as follows: vehicles and furniture and fixtures — 5 to 10 years; and computer equipment and software — 3 to 5 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.

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, 2009 and 2008, our aggregate oil and natural gas imbalances were not material to our consolidated financial statements.

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

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. 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 and accordingly the changes in the fair value of these instruments are recognized in income in the period of change. See Note 10 for further information on our derivative contracts.

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. Also, most of our significant purchasers are large companies with excellent credit ratings. 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. There are no margin requirements with the counterparties of our derivative contracts.

CO_2 OPERATIONS

We own and produce CO_2 reserves that are used for our own tertiary oil recovery operations, and in addition, we sell a portion to Genesis and to other third party industrial users. We record revenue from our sales of CO_2 to third parties when it is produced and sold. CO_2 used for our own tertiary oil recovery operations is not recorded as revenue in the Consolidated Statements of Operations. Expenses related to the production of CO_2 are allocated between volumes sold to third parties and volumes used for our own use. The expenses related to third party sales are recorded in "CO_2 operating expenses" and the expenses related to our own uses 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" on page 76 for further discussion). We capitalize acquisitions and the costs of exploring and developing CO_2 reserves. The costs capitalized are depleted or depreciated on the unit-of-production method, based on proved CO_2 reserves as determined by independent engineers. To evaluate our CO_2 assets for impairment, we determine the CO_2 required for our proved tertiary reserves and include the estimated net capitalized costs of those CO_2 assets in the oil and natural gas ceiling test. The remaining net capitalized CO_2 asset cost is evaluated for impairment by comparing our expected future revenues from these assets to their net carrying value.

CO_2 PIPELINES

CO_2 pipelines are used for transportation of CO_2 to our tertiary floods from our CO_2 source field located near Jackson, Mississippi. We are continuing expansion of our CO_2 pipeline infrastructure with several pipelines currently under construction. At December 31, 2009 and 2008, we had $779.1 million and $402.0 million of costs, respectively, related to construction in progress, recorded under "CO_2 properties, equipment and pipelines" in our Consolidated Balance Sheets. These costs of CO_2 pipelines under construction were not being depreciated at December 31, 2009 or December 31, 2008. Depreciation will commence when the pipelines are placed into service. The Green Pipeline, which had $766.9 million in cost, including capitalized interest, at December 31, 2009, is expected to be placed into service during 2010. Each pipeline is depreciated on a straight-line basis over its estimated useful life, which ranges from 20 to 30 years. We include the net capitalized cost of the pipelines which provide CO_2 to the tertiary floods that have proved tertiary reserves, in the oil and natural gas ceiling test.

GOODWILL

We recorded goodwill during 2009 in conjunction with our Hastings Field and Conroe Field acquisitions (see Note 2, "Acquisitions and Divestitures"). 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, but rather it is tested for impairment annually during the fourth quarter and also when events or changes in circumstances indicate that the fair value of a reporting unit with goodwill has been reduced below carrying value. The impairment test requires allocating goodwill and other assets and liabilities to reporting units. In the case of Denbury, we have only one reporting unit. The fair value of the reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, including goodwill, the recorded goodwill is impaired to its implied fair value with a charge to operating expense. We completed our annual goodwill impairment test during the fourth quarter of 2009 and did not record goodwill impairment during 2009.

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 AND INVESTMENTS

At December 31, 2009 and 2008, we had approximately $22.8 million and $7.4 million, respectively, of restricted cash and investments held in escrow accounts for future site reclamation costs. These balances are recorded at amortized cost and are included in "Other assets" in the Consolidated Balance Sheets. The estimated fair market value of these investments at December 31, 2009 and 2008 was approximately the same as amortized cost.

NET INCOME PER COMMON SHARE

Basic net income per common share is computed by dividing the net income attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income per common share is calculated in the same manner, but also considers the impact to net income and common shares for the potential dilution from stock options, non-vested stock appreciation rights ("SARs"), non-vested restricted stock and any other convertible securities outstanding.

All shares have been adjusted for the 2-for-1 stock split effective December 5, 2007. For each of the three years in the period ended December 31, 2009, 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 computations:

In thousands	Year Ended December 31, 2009	2008	2007
Weighted average common shares – basic	**246,917**	**243,935**	**240,065**
Potentially dilutive securities:			
Stock options and SARs	**—**	**7,102**	**10,485**
Restricted stock	**—**	**1,493**	**1,551**
Weighted average common shares – diluted	**246,917**	**252,530**	**252,101**

The weighted average common shares – basic amount in 2009, 2008 and 2007 excludes 2.5 million, 2.2 million and 2.7 million shares of non-vested restricted stock, respectively, that is subject to future vesting over time. As these restricted shares vest, 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 weighted average common shares – diluted, the non-vested restricted stock is included in the computation using the treasury stock method, with the 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 earnings per share as their effect would have been anti-dilutive:

In thousands	Year Ended December 31, 2009	2008	2007
Stock options and SARs	**10,764**	**1,098**	**130**
Performance equity awards	**523**	**—**	**—**
Restricted stock	**2,507**	**—**	**—**
Total	**13,794**	**1,098**	**130**

INCOME TAXES

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

Effective January 1, 2007, we adopted new accounting guidelines codified in the "Income Taxes" topic of the FASC that address how tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under the revised guidance, the Company may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on 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 should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. See Note 7, "Income Taxes," for further information regarding our income taxes.

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 (i) the fair value of financial derivative instruments, (ii) 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 ceiling test,

(iii) accruals related to oil and gas production and revenues, capital expenditures and lease operating expenses, (iv) the estimated costs and timing of future asset retirement obligations, (v) estimates made in the calculation of income taxes and, (vi) estimates made in determining the fair values for purchase price allocations. 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 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 gas industry, many of which require retroactive application. These types of adjustments cannot be currently estimated and will be recorded in the period during 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.

RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

FASB Accounting Standards Codification™. In June 2009, the Financial Accounting Standards Board ("FASB") introduced the FASC as the new source of authoritative U.S. GAAP for nongovernmental entities. The Company applied the new guidance to our financial statements issued for the nine months ended September 30, 2009. This standard did not have any impact on the Company's financial position or results of operations.

Subsequent Events. In May 2009, the FASB issued guidance under the "Subsequent Events" topic of the FASC to establish accounting standards for events that occur after the balance sheet date but before financial statements are issued or are available to be issued. The new guidance does not significantly change current practice but does require companies to disclose the date through which subsequent events were evaluated and whether or not that date was the date the financial statements were issued or available for issuance. The Company adopted the new guidance upon its issuance with no resulting impact on the Company's financial position or results of operations.

Business Combinations. In December 2007, the FASB issued guidance under the "Business Combinations" topic of the FASC to establish principles and requirements for how an acquirer recognizes and measures in its financial statements, the identifiable assets acquired, the liabilities assumed, any noncontrolling interest in the acquiree and the goodwill acquired. The guidance also establishes disclosure requirements to enable the evaluation of the nature and financial effects of the business combination. We adopted the new guidance on January 1, 2009. While the adoption did not have an adoption-date impact on our financial position or results of operations, we did apply the revised guidance to our Hastings Field and Conroe Field acquisitions during 2009.

Equity Method Accounting. In November 2008, the FASB issued guidance in the "Investments – Equity Company and Joint Ventures" topic of the FASC to clarify how the application of equity method accounting will be affected by newly issued guidance on business combinations and noncontrolling interests in consolidated financial statements. The new guidance clarifies that an entity shall continue to use the cost accumulation model for its equity method investments. It also confirms past accounting practices related to the treatment of contingent consideration and impairment. Additionally, it requires an equity method investor to account for a share issuance by an investee as if the investor had sold a proportionate share of the investment. This guidance was effective January 1, 2009, applies prospectively and did not have any impact on our financial position or results of operations.

Noncontrolling Interests. In December 2007, the FASB issued guidance under "Consolidations" topic of the FASC which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent's ownership interest, and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. The new guidance also establishes disclosure requirements that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. We adopted this guidance on January 1, 2009 and, since we currently do not have any noncontrolling interests, the adoption did not have any impact on our financial position or results of operations.

Disclosures about Derivative Instruments and Hedging Activities. In March 2008, the FASB issued guidance under the "Derivatives and Hedging" topic of the FASC which requires entities that utilize derivative instruments to provide qualitative disclosures about their objectives and strategies for using such instruments, as well as any details of credit risk related contingent features contained within derivatives. The guidance also requires entities to disclose additional information about the amounts and location of derivatives within the financial statements, how the provisions of accounting guidance related to derivatives and hedging have been applied, and the impact that hedges have on an entity's financial position, financial performance, and cash flows. We adopted the disclosure requirement beginning January 1, 2009 (see Note 10, "Derivative Instruments and Hedging Activities"). The adoption of this statement did not have any impact on our financial position or results of operations.

Fair Value Measurements. In 2006, the FASB issued guidance which defined fair value, established a framework for measuring fair value and expanded disclosures about fair value measurements. In February 2008, the FASB delayed the effective date of the new guidance for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). We adopted the new guidance on January 1, 2009. The adoption of this guidance did not have any impact on our financial position or results of operations.

In April 2009, the FASB issued new rules to provide additional application guidance and enhance disclosures regarding fair value measurements and impairments of securities. The FASB enhanced its guidance under the "Fair Value Measurements and Disclosures" topic of the FASC to 1) determine fair value when the volume and level of activity for an asset or liability have significantly decreased and 2) identify transactions that are not orderly. The FASB issued guidance under the "Financial Instruments" topic of the FASC to enhance consistency in financial reporting by increasing the frequency of fair value disclosures. The FASB also issued guidance in the "Investments – Debt and Equity Securities" topic of the FASC to provide additional guidance to create greater clarity and consistency in accounting for and presenting impairment losses on securities. The new guidance was effective for interim and annual periods ending after June 15, 2009. Although adoption of the guidance enhanced our interim financial statement disclosures, it did not have any impact on our financial position or results of operations.

In August 2009, the FASB issued guidance under the "Fair Value Measurements and Disclosures" topic of the FASC to provide additional guidance on measuring the fair value of liabilities. The new guidance was effective for the Company on October 1, 2009, and did not have any impact on the Company's financial position or results of operations.

Modernization of Oil and Gas Reporting. On December 31, 2008, the Securities and Exchange Commission adopted major revisions to its rules governing oil and gas company reporting requirements. These include provisions that permit the use of new technologies to determine proved reserves, and allow companies to disclose their probable and possible reserves to investors. The prior rules limited disclosure to only proved reserves. The new rules also require companies that have an audit performed on their reserves to report the independence and qualifications of the reserve auditor, and file reports when a third party reserve engineer is relied upon to prepare reserve estimates. The new rules also require that oil and gas reserves be reported and the full cost ceiling value be calculated using an average of first-day-of-the-month prices for the prior twelve-month period. In January 2010, the FASB issued guidance in the "Extractive Activities – Oil and Gas" topic of the FASC that aligns the FASB's oil and gas reserve estimation and disclosure requirements with the new SEC rule revisions. The new guidance is effective for the Company for the year ending December 31, 2009. The revised guidance did not have a material impact on our financial position or results of operations. It did, however, impact the prices we use to estimated proved reserves and the standardized measure of future net cash flows (see Note 16, "Supplemental Oil and Natural Gas Disclosures").

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

Transfers of Financial Assets. In June 2009, the FASB issued guidance related to the accounting for transfers of financial assets. The guidance removes the concept of a qualifying special-purpose entity ("QSPE") from FASC topic "Transfers and Servicing", creates a new unit of account definition that must be met for transfers of portions of financial assets to be eligible for sale accounting, clarifies the de-recognition criteria for a transfer to be accounted for as a sale, changes the amount of recognized gains or losses on the transfer of financial assets accounted for as a sale when beneficial interests are received by the transferor and introduces new disclosure requirements. The new guidance is effective for us beginning January 1, 2010. The adoption will not have a material impact on our financial condition or results of operations.

Consolidation of Variable Interest Entities. In June 2009, the FASB issued guidance to eliminate the exemption in the "Consolidation" topic of the FASC for QSPEs, introduce a new approach for determining who should consolidate a variable interest entity and change the requirement as to when it is necessary to reassess who should consolidate a variable interest entity. We adopted the standard on January 1, 2010. The adoption will not have a material impact on our financial condition or results of operations.

Fair Value Disclosures. In January 2009, the FASB issued guidance in the "Fair Value Measurements and Disclosures" topic of the FASC to enhance disclosures surrounding the transfers of assets in and out of level 1 and level 2, to present more detail surrounding asset activity for level 3 assets and to clarify existing disclosure requirements. The new guidance is effective for the Company beginning January 1, 2010, and will not have any impact on our financial position or statement of operations.

NOTE 2. ACQUISITIONS AND DIVESTITURES

2009 ACQUISITIONS

Conroe Field Acquisition. In August 2008, we entered into an agreement with a privately owned company to purchase a 91.4% interest in Conroe Field, a significant potential tertiary flood north of Houston, Texas, for $600 million, plus additional potential consideration if oil prices were to exceed $121 per barrel during the next three years. Closing was provided for in early October 2008. Based on capital market conditions in early October, and a desire to refrain from increasing our leverage in that environment, we cancelled the contract to purchase the Conroe Field, forfeiting a $30 million non-refundable deposit. The $30 million deposit plus miscellaneous acquisition costs of $0.6 million are included in "Abandoned acquisition costs" in our Consolidated Statement of Operations for the year ended December 31, 2008.

On December 18, 2009, we purchased Conroe Field for consideration consisting of approximately $254.2 million in cash (before closing adjustments) and 11,620,000 shares of our common stock. The common stock was valued at $168.7 million based on the closing date price of our stock on December 18, 2009 of $14.52. The effective date of purchase was December 1, 2009, and consequently operating net revenues, net of capital expenditures, from December 1, 2009 through December 18, 2009 will be accounted for as adjustments to the ultimate purchase price. The cash amount paid at closing was $269.8 million, which reflects $15.6 million for amounts in escrow accounts reserved for plugging and abandonment and other adjustments. We believe the acquisition includes significant opportunities for enhanced oil recovery using our available sources of CO_2, which we have recorded as unevaluated oil and gas properties as determined under the FASC "Fair Value Measurement" topic (see "Purchase Price Allocations" below). During the year ended December 31, 2009, we recognized $2.3 million and $1.4 million of revenues and net field operating income (revenues less production taxes and lease operating expenses), respectively, related to our acquisition of Conroe Field. Acquisition-related costs (legal, accounting, due diligence, etc.) have been expensed.

Denbury shares issued to Wapiti in conjunction with the purchase of Conroe Field are subject to a registration rights agreement whereby Denbury has agreed to register the shares with the SEC and maintain the effectiveness of the shares for a period of time which we currently estimate to be one year. The shares were registered with the SEC on February 2, 2010.

Hastings Field Acquisition. During November 2006, we entered into an agreement with a subsidiary of Venoco, Inc., that gave us an option to purchase their interest in Hastings Field, a strategically significant potential tertiary flood candidate located near Houston, Texas. We exercised the purchase option prior to September 2008, and closed the acquisition during February 2009. As consideration for the option agreement, during 2006 through 2008, we made cash payments totaling $50 million which we recorded as a deposit. The remaining purchase price of approximately $196 million was paid in cash, and was determined as of January 1, 2009 (the effective date) with closing on February 2, 2009. The final closing adjustments were completed during the three months ended September 30, 2009. The final closing price, adjusted for interim net cash flows between the effective date and closing date of the acquisition (including minor purchase price adjustments), totaled $246.8 million. During the year ended December 31, 2009, we recognized \$43.5 million and \$18.8 million of revenues and net field operating income (revenues less production taxes and lease operating expenses), respectively, related to our acquisition of Hastings Field. The acquisition-related costs (legal, accounting, due diligence, etc.) have been expensed.

Under the terms of the agreement, Venoco, Inc., the seller, retained a 2% override and a reversionary interest of approximately 25% following payout, as defined in the option agreement. We plan to commence flooding the field with CO_2 beginning in 2011, after completion of our Green Pipeline currently under construction and construction of field recycling facilities. Under the agreement, we are required to make aggregate net cumulative capital expenditures in this field of approximately \$179 million prior to December 31, 2014 as follows: \$26.8 million by December 31, 2010, \$71.5 million by December 31, 2011, \$107.2 million by December 31, 2012, \$142.9 million by December 31, 2013, and \$178.7 million by December 31, 2014. If we fail to spend the required amounts by the due dates, we are required to make a cash payment equal to 10% of the cumulative shortfall at each applicable date. During 2009, we made capital expenditures related to CO_2 flood development at Hastings Field totaling \$1.7 million. Further, we are committed to inject at least an average of 50 MMcf/day of CO_2 (total of purchased and recycled) in the West Hastings Unit for the 90-day period prior to January 1, 2013. If such injections do not occur, we must either (1) relinquish our rights to initiate (or continue) tertiary operations and reassign to Venoco all assets previously purchased for the value of such assets at that time based upon the discounted value of the field's proved reserves using a 20% discount rate, or (2) make an additional payment of \$20 million in January 2013, less any payments made for failure to meet the capital spending requirements as of December 31, 2012, and a \$30 million payment for each subsequent year (less amounts paid for capital expenditure shortfalls) until the CO_2 injection rate in the Hastings Field equals or exceeds the minimum required injection rate. At this time, the Company believes it will be compliant with both of these commitments.

Purchase Price Allocations. Conroe Field and Hastings Field meet the definition of a business under the FASC "Business Combinations" topic. As such, we estimated the fair value of each property as of the acquisition date, as defined in the FASC, is the date on which the acquirer obtains control of the acquiree, which was the closing date for both Conroe and Hastings Fields. 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 should not impact the measurement of fair value unless those assumptions are consistent with market participant views.

In applying these accounting principles, we estimated the fair value of the assets acquired as follows:

In thousands	Conroe Field	Hastings Field
Proved oil and natural gas properties	**\$304,313**	**\$107,582**
Unevaluated oil and natural gas properties	**93,585**	**—**
Other assets	**15,654**	**2,425**
Asset retirement obligations	**(5,705)**	**(2,067)**
Goodwill	**30,687**	**138,830**
	\$438,534	**\$246,770**

The FASC defines goodwill as an asset representing the future economic benefits arising from other assets acquired in a business combination that are not individually identified and separately recognized. For the Conroe Field and Hastings Field acquisitions, goodwill is the excess of the consideration paid to acquire these fields over their acquisition date estimated fair values. Goodwill recorded in both the Conroe Field and Hastings Field acquisitions is due to the estimated fair value assigned to the estimated oil reserves recoverable through a CO_2 enhanced oil recovery ("EOR") project. Denbury has 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. This source of CO_2 that we own will allow Denbury to carry out CO_2 EOR activities in this field at a much lower cost than other market participants. However, 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 an estimated cost of CO_2 to other market participants. This assumption of a higher cost of CO_2 resulted in an estimated fair value of the projected CO_2 EOR reserves that would not have been economically viable at Hastings Field on the acquisition date and resulted in a lower fair value assigned to undeveloped property in the Conroe Field acquisition. In addition, goodwill recorded in the Hastings Field acquisition is also due to the decrease in the NYMEX oil and natural gas futures prices between the effective date of January 1, 2009, which is the date at which the acquisition price was determined, and the acquisition date of February 2, 2009, which is the date at which the assets were valued for accounting purposes. The purchase agreement provided that the Hastings Field reserves be valued using the NYMEX oil and gas futures prices on the effective date of January 1, 2009.

The fair value of Conroe Field and Hastings Field was based on significant inputs not observable in the market, which FASC "Fair Value Measurements and Disclosures" topic defines as Level 3 inputs. Key assumptions include (1) NYMEX oil and natural gas futures (this input is observable), (2) projections of the estimated quantities of oil and natural gas reserves, (3) projections of future rates of production, (4) timing and amount of future development and operating costs, (5) projected cost of CO_2 to a market participant, (6) projected recovery factors and, (7) risk adjusted discount rates. Goodwill is deductible for tax purposes. The Conroe Field purchase price allocation is preliminary and subject to changes resulting from final closing adjustments.

Unaudited Pro Forma Information. Had our acquisitions of both Conroe Field and Hastings Fields occurred on January 1, 2009 and January 1, 2008, Denbury's combined pro forma revenue and net income (loss) would have been as follows:

	Year Ended December 31,	
In thousands	2009	2008
Revenues	**$937,986**	**$1,547,776**
Net income (loss)	**(71,774)**	**422,707**

2009 DISPOSITIONS

May 2009 Sale of 60% of Denbury's Barnett Shale Natural Gas Assets. In May 2009, we entered into an agreement to sell 60% of our Barnett Shale natural gas assets to Talon Oil and Gas LLC ("Talon"), a privately held company, for $270 million (before closing adjustments). We closed on approximately three-quarters of the sale in June 2009 and closed on the remainder of the sale in July 2009. Net proceeds were $259.8 million (after preliminary closing adjustments, and net of $8.1 million for natural gas swaps transferred in the sale). The agreement has an effective date of June 1, 2009, and consequently operating net revenues after June 1, net of capital 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.

December 2009 Sale of Remaining 40% of Denbury's Barnett Shale Natural Gas Assets. In December 2009, Denbury closed the sale of its remaining 40% interest in Barnett Shale natural gas assets to Talon for $210 million (before closing adjustments). The effective date under the agreement was December 1, 2009. Denbury did not record a gain or loss on the sale in accordance with the full cost method of accounting.

2007 ACQUISITIONS AND DISPOSITIONS

Sale of Louisiana Natural Gas Asset. In October 2007, we entered into an agreement to sell our Louisiana natural gas assets to a privately held company for approximately $180 million (before closing adjustments) plus we retained a net profits interest in one well. In late December 2007, we closed on approximately 70% of that sale with net proceeds of approximately $108.6 million (including estimated final purchase price adjustments). We closed on the remaining portion of the sale in February 2008 and received net proceeds of approximately $48.9 million. The agreement was effective August 1, 2007, and consequently operating net revenue after August 1, net of capital expenditures, along with any other minor closing items were adjustments to the purchase price. The potential net profits interest relates to a well in the South Chauvin field and is only earned if operating income from that well exceeds certain levels. During 2009, we began receiving revenue payments related to the net profits interest in this well. The operating results of these sold properties are included in our financial statements through the applicable closing dates of the sold properties. We did not record any gain or loss on the sale in accordance with the full cost method of accounting.

Purchase of Seabreeze Complex. On March 30, 2007, Denbury completed the acquisition of the Seabreeze Complex, which is composed of two significant fields and four smaller fields in the general area of Houston, Texas. Two of these fields are future potential CO_2 tertiary flood candidates. Tertiary flooding at one of these fields, Oyster Bayou, is expected to begin during 2010. The adjusted purchase price was approximately $39.4 million, of which $33.9 million was assigned to unevaluated properties.

NOTE 3. RELATED PARTY TRANSACTIONS – GENESIS

Interest in and Transactions with Genesis

Denbury's former subsidiary, Genesis Energy, LLC, is the general partner of, and together with Denbury's other subsidiaries, at December 31, 2009, owned an aggregate 12% interest in Genesis, a publicly traded master limited partnership. On February 5, 2010, we sold our interest in Genesis Energy, LLC (see Note 15, "Subsequent Events"). Genesis' business is focused on the mid stream segment of the oil and gas industry in the Gulf Coast area of the United States, and its activities include gathering, marketing and transportation of crude oil and natural gas, refinery services, wholesale marketing of CO_2, and supply and logistic services.

Prior to the sale, we accounted for our 12% ownership in Genesis under the equity method of accounting as we had significant influence over the limited partnership; however, our control was limited under the limited partnership agreement and therefore we did not consolidate Genesis. Denbury received cash distributions from Genesis of $11.6 million in 2009, $7.1 million in 2008, and $1.7 million in 2007. We also received $0.2 million in 2009 and 2008 and $0.1 million in 2007, in directors' fees for certain officers of Denbury that were board members of Genesis prior to the February 5, 2010 sale of our General Partner ownership. There are no guarantees by Denbury or any of our other subsidiaries of the debt of Genesis or of Genesis Energy, LLC.

We continue to own an aggregate of 4,028,096 common units of Genesis, representing an approximate 10% limited partnership interest, for which a resale registration statement was filed in January 2010. We also continue to account for our remaining 10% ownership interest in Genesis under the equity method of accounting. Our cumulative investments in Genesis of $85.5 million exceeded our percentage of net equity in the limited partnership at the time of acquisition by approximately $15.7 million, which represents goodwill and is not subject to amortization. At December 31, 2009, the balance of our total equity investment in Genesis was $75.0 million (see Note 15, "Subsequent Events – Sale of General Partner Interest in Ownership in Genesis"). Based on quoted market values of Genesis' publicly traded limited partnership units at December 31, 2009, the estimated market value of our publicly traded common units of Genesis was approximately $76.1 million.

Incentive Compensation Agreement

In late December 2008, our subsidiary, Genesis Energy, LLC, entered into agreements with three members of Genesis management, for the purpose of providing them incentive compensation, which agreements make them Class B Members in Genesis Energy, LLC, and each an owner of a Class B ownership interest. The awards are mandatorily redeemable upon a change in control and require the membership interests of the holders of the awards to be redeemed for cash (or in certain circumstances Genesis limited partnership units) by Genesis Energy, LLC. Upon the sale by Denbury of our interest in Genesis Energy, LLC in February 2010, the change in control provision of each member's compensation agreement was triggered. As such, the awards were settled for cash in February 2010 for $14.9 million. As of December 31, 2009, we had approximately $13.8 million recorded under "Accounts payable and accrued liabilities" for these awards in our Consolidated Balance Sheet. We recorded approximately $14.2 million for the year ended December 31, 2009, in "General and administrative" expenses on our Consolidated Statement of Operations, of which $0.4 million relates to cash payments made under these awards and $13.8 million is associated with the fair value of the award.

NEJD Pipeline and Free State Pipeline Transactions

On May 30, 2008, we closed on two transactions with Genesis involving our Northeast Jackson Dome ("NEJD") pipeline system and Free State Pipeline, which included a 20-year financing lease for the NEJD system and a long-term transportation service agreement for the Free State Pipeline. We have recorded both of these transactions as financing leases. At December 31, 2009, we have recorded $170.6 million for the NEJD financing and $80.0 million for the Free State Pipeline as debt, of which $3.8 million was included in current liabilities in our Consolidated Balance Sheet. At December 31, 2008, we had recorded $173.6 million for the NEJD financing and $76.6 million for the Free State Pipeline as debt, of which $3.0 million was included in current liabilities in our Consolidated Balance Sheet (see Note 6, "Long-term Debt").

Oil Sales and Transportation Services

We utilize Genesis' trucking services and common carrier pipeline to transport certain of our crude oil production to sales points where it is sold to third party purchasers. We expensed $7.9 million in 2009, $8.0 million in 2008, and $6.0 million in 2007 for these transportation services.

Transportation Leases

We have pipeline transportation agreements with Genesis to transport our crude oil from certain of our fields in Southwest Mississippi, and to transport CO_2 from our main CO_2 pipeline to Brookhaven Field for our tertiary operations. We have accounted for these agreements as capital leases. The pipelines held under these capital leases are classified as property and equipment and are amortized using the straight-line method over the lease terms. Lease amortization is included in depreciation expense. The related obligations are recorded as debt. At December 31, 2009 and 2008, we had $3.8 million and $4.5 million, respectively, of capital lease obligations with Genesis recorded as liabilities in our Consolidated Balance Sheets.

CO_2 Volumetric Production Payments

During 2003 through 2005, we sold 280.5 Bcf of CO_2 to Genesis under three separate volumetric production payment agreements. We have recorded the net proceeds of these volumetric production payment sales as deferred revenue and recognize such revenue as CO_2 is delivered under the volumetric production payments. At December 31, 2009 and 2008, $19.8 million and $24.0 million, respectively, was recorded as deferred revenue of which $4.1 million was included in current liabilities at both December 31, 2009 and 2008. We recognized deferred revenue of $4.2 million, $4.5 million and $4.4 million for the years ended December 31, 2009, 2008 and 2007, respectively, for deliveries under these volumetric production payments. We provide Genesis with certain processing and transportation services in connection with transporting CO_2 to their industrial customers for a fee of approximately $0.20 per Mcf of CO_2. For these services, we recognized revenues of $5.5 million, $5.5 million and $5.2 million for the years ended December 31, 2009, 2008 and 2007, respectively.

NOTE 4. ASSET RETIREMENT OBLIGATIONS

In general, our future asset retirement obligations relate to future costs associated with plugging and abandonment of our oil, natural gas and CO_2 wells, removal of equipment and facilities from leased acreage and land restoration. The fair value of a liability for an asset retirement 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.

The following table summarizes the changes in our asset retirement obligations for the years ended December 31, 2009 and 2008.

	Year Ended December 31,	
In thousands	2009	2008
Beginning asset retirement obligation	**$45,064**	**$41,258**
Liabilities incurred and assumed during period	**8,911**	**1,382**
Revisions in estimated retirement obligations	**2,357**	**4,456**
Liabilities settled during period	**(3,478)**	**(4,711)**
Accretion expense	**3,280**	**3,048**
Sales	**(1,796)**	**(369)**
Ending asset retirement obligation	**$54,338**	**$45,064**

At December 31, 2009 and 2008, $1.1 million and $1.7 million, respectively, of our asset retirement obligation was classified in "Accounts payable and accrued liabilities" under current liabilities in our Consolidated Balance Sheets. Liabilities incurred and assumed during 2009 are primarily related to the acquisition of Hastings Field and Conroe Field. Liabilities incurred and assumed during 2008 were primarily for new wells drilled. Liabilities sold during 2009 are primarily related to our Barnett Shale natural gas properties (see Note 2, "Acquisitions and Divestitures"). Liabilities sold in 2008 were primarily associated with the sale of our Louisiana natural gas properties in February 2008. The reversal of these asset retirement obligations, which were assumed by the purchasers, was recorded as an adjustment to the full cost pool with no gain or loss recognized, in accordance with the full cost method of accounting. We have escrow accounts that are legally restricted for certain of our asset retirement obligations. The balances of these escrow accounts were $22.8 million and $7.4 million at December 31, 2009 and 2008, respectively, and are included in "Other assets" in our Consolidated Balance Sheets. The increase in the escrow balance is related to escrow accounts acquired in the Conroe Field acquisition.

NOTE 5. PROPERTY AND EQUIPMENT

In thousands	December 31, 2009	December 31, 2008
Oil and natural gas properties		
Proved properties	$ 3,595,726	$ 3,386,606
Unevaluated properties	320,356	235,403
Total	3,916,082	3,622,009
Accumulated depletion and depreciation	(1,685,171)	(1,481,801)
Net oil and natural gas properties	2,230,911	2,140,208
CO_2 properties and equipment	438,045	377,711
Accumulated depletion and depreciation	(79,196)	(60,758)
Net CO_2 properties	358,849	316,953
CO_2 pipelines in service	312,656	119,819
CO_2 pipelines under construction	779,080	402,012
Accumulated depletion and depreciation	(22,426)	(16,392)
Net CO_2 pipelines	1,069,310	505,439
Capital leases	9,857	9,565
Accumulated depletion and depreciation	(4,787)	(3,333)
Net capital leases	5,070	6,232
Other	72,680	60,763
Accumulated depletion and depreciation	(33,948)	(27,398)
Net other	38,732	33,365
Net property and equipment	$ 3,702,872	$ 3,002,197

At December 31, 2009 and 2008, we had $779.1 million and $402.0 million of costs, respectively, related to pipelines under construction, and as such, were not being depreciated at December 31, 2009 or December 31, 2008, respectively. Depreciation will commence when the pipelines are placed into service. The Green Pipeline, which had $766.9 million in cost, including capitalized interest, at December 31, 2009, is expected to be placed into service during 2010. The Company capitalizes interest on its CO_2 pipelines during the construction period. Interest capitalized on these CO_2 pipelines was $54.2 million in 2009 and $11.5 million in 2008.

Unevaluated Oil and Natural Gas Properties Excluded From Depletion

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. 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. The costs classified as unevaluated are transferred to the full cost amortization base as the properties are developed, tested and evaluated. A summary of the unevaluated properties excluded from oil and natural gas properties being amortized at December 31, 2009, and the year in which they were incurred follows:

	December 31, 2009				
	Costs Incurred During:				
In thousands	2009	2008	2007	2006 and prior	Total
Property acquisition costs	$ 95,477	$ 2,573	$31,042	$70,350	$199,442
Exploration and development	68,530	21,898	2,645	—	93,073
Capitalized interest	12,477	7,442	5,341	2,581	27,841
Total	$176,484	$31,913	$39,028	$72,931	$320,356

Property acquisition costs for 2009 are primarily for CO_2 tertiary potential at Conroe Field. Property acquisition costs for 2007 are primarily for CO_2 tertiary oil field candidates acquired in the Seabreeze Complex. Property acquisition costs for 2006 and prior are primarily for Delhi Field, South Cypress Creek Field, and Citronelle Field. We commenced CO_2 injection at Delhi Field in November 2009 and we plan to commence CO_2 injection at Seabreeze in mid-2010. See Note 2, "Acquisitions and Divestitures." Exploration and development costs are primarily associated with our CO_2 tertiary oil fields that are under development and did not have proved reserves at December 31, 2009. During 2009, we established proved reserves at Cranfield Field and as a result we transferred $82.4 million of costs incurred on this project into the amortization base. Costs are transferred into the amortization base on an ongoing basis as the 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.

Full Cost Ceiling Test

In 2008 the Company recognized a write-down of its oil and natural gas properties of $226 million under the full cost ceiling test at December 31, 2008. In accordance with the full cost ceiling rules at December 31, 2008, the ceiling limit was calculated utilizing the unescalated period-end prices, which were a NYMEX WTI oil price per Bbl of $44.60 and a Henry Hub cash price per MMBtu of $5.71. We included the portion of net capitalized cost of CO_2 assets and CO_2 pipelines that were required for our proved tertiary reserves in the net capitalized costs subject to this ceiling test. The fair value of our oil derivative contracts at December 31, 2008 of $249.7 million, which contracts had a floor price of $75.00 per barrel on 30,000 barrels per day for calendar year 2009, was not included in the ceiling test as we did not designate these contracts as hedge instruments for accounting purposes.

Because oil prices have recovered during 2009 from their year-end 2008 levels, we did not have a ceiling test write-down during 2009. However, if oil prices were to decrease significantly in subsequent periods, we may be required to record additional 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 reserve estimates and future capital expenditures, and additional capital spent. The SEC adopted major revisions to its rules governing oil and gas company reporting requirements which are effective for us beginning with this December 31, 2009, Form 10-K. Under these new rules, the full cost ceiling value is calculated using an average price based on the first day of every month during the period.

NOTE 6. LONG-TERM DEBT

In thousands	December 31, 2009	2008
9.75% Senior Subordinated Notes due 2016	$ 426,350	$ —
Discount on Senior Subordinated Notes due 2016	(26,424)	—
7.5% Senior Subordinated Notes due 2015	300,000	300,000
Premium on Senior Subordinated Notes due 2015	513	599
7.5% Senior Subordinated Notes due 2013	225,000	225,000
Discount on Senior Subordinated Notes due 2013	(631)	(826)
NEJD financing – Genesis	170,633	173,618
Free State financing – Genesis	79,987	76,634
Senior bank loan	125,000	75,000
Capital lease obligations – Genesis	3,780	4,544
Capital lease obligations	2,168	2,705
Total	1,306,376	857,274
Less current obligations	5,308	4,507
Long-term debt and capital lease obligations	$1,301,068	$852,767

9.75% Senior Subordinated Notes due 2016

On February 13, 2009, we issued $420 million of 9.75% Senior Subordinated Notes due 2016 ("2016 Notes"). The 2016 Notes, which carry a coupon rate of 9.75%, were sold at a discount (92.816% of par), which equates to an effective yield to maturity of approximately 11.25%. The net proceeds of $381.4 million were used to repay most of our then-outstanding borrowings under our bank credit facility, which increased from the December 31, 2008 balance, primarily associated with the funding of the Hastings Field acquisition (see Note 2, "Acquisitions and Divestitures"). In conjunction with this debt offering we amended our bank credit facility in early February 2009, which, among other things, allowed us to issue these senior subordinated notes.

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

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

NEJD Financing and Free State Financing

On May 30, 2008, we closed on two transactions with Genesis involving two of our pipelines. The two transactions have been recorded as financing leases. See Note 3, "Related Party Transactions – Genesis – NEJD Pipeline and Free State Pipeline Transactions."

7.5% Senior Subordinated Notes due 2015

On April 3, 2007, we issued $150 million of Senior Subordinated Notes due 2015 as an additional issuance under our existing indenture governing our December 2005 sale of $150 million of 7.5% Senior Subordinated Notes due 2015 (collectively, the "2015 Notes") discussed below. These notes, which carry a coupon rate of 7.5%, were sold at 100.5% of par, which equates to an effective yield to maturity of approximately 7.4%. Net proceeds from the sale were approximately $149.2 million. The net proceeds were used to repay a portion of the outstanding borrowings under our bank credit facility.

The $150 million of 2015 Notes issued on December 21, 2005 were priced at par, and we used the $148.0 million of net proceeds from the offering to fund a portion of the $250 million oil and natural gas property acquisition, which closed in January 2006. The 2015 Notes mature on December 15, 2015, and interest on the 2015 Notes is payable each June 15 and December 15. We may redeem the 2015 Notes at our option beginning December 15, 2010, at the following redemption prices: 103.75% after December 15, 2010, 102.5% after December 15, 2011, 101.25% after December 15, 2012, and 100% after December 15, 2013. The indenture 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 2015 Notes are not subject to any sinking fund requirements. All of our significant subsidiaries fully and unconditionally guarantee this debt.

7.5% Senior Subordinated Notes due 2013

On March 25, 2003, we issued $225 million of 7.5% Senior Subordinated Notes due 2013 ("2013 Notes"). The 2013 Notes were priced at 99.135% of par. The 2013 Notes mature on April 1, 2013, and interest on the 2013 Notes is payable each April 1 and October 1. We may redeem the 2013 Notes at our option beginning April 1, 2008, at the following remaining redemption prices: 102.5% after April 1, 2009, 101.25% after April 1, 2010, and 100% after April 1, 2011, and thereafter. The indenture 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 2013 Notes are not subject to any sinking fund requirements. All of our significant subsidiaries fully and unconditionally guarantee this debt.

Issuance of 8.25% Senior Subordinated Notes Due 2020

On February 10, 2010, we issued $1 billion of 8.25% Senior Subordinated Notes due 2020. (See Note 15, "Subsequent Events").

Senior Bank Loan

To clarify that Denbury entities are allowed to guarantee obligations of other Denbury entities, in May 2009 we amended our Sixth Amended and Restated Credit Agreement, the instrument governing our Senior Bank Loan, to explicitly permit these guarantees and waive any possible previous technical violations of this provision.

In June and December 2009, we again amended our Senior Bank Loan agreement. The June 2009 amendment was made in conjunction with the sale of our Barnett Shale natural gas properties, and (i) reduced our borrowing base from $1.0 billion to $900 million, and (ii) allowed for an additional percentage of our forecasted production to be hedged through June 30, 2009. The June amendment did not impact the banks' commitment amount, which remained at $750 million. The December 2009 amendment was made in conjunction with our acquisition of Conroe Field and the sale of our remaining interests in the Barnett Shale natural gas properties. This December amendment (i) allowed for the consummation of the Conroe-Barnett transactions, and (ii) allowed for an additional percentage of our forecasted production to be hedged through May 31, 2010. Our borrowing base of $900 million did not change as a result of this December amendment.

With regard to our bank credit facility, the borrowing base represents the amount that can be borrowed from a credit standpoint based on our mortgaged assets, as confirmed by the banks, while the commitment amount is the amount the banks have committed to fund pursuant to the terms of the credit agreement. The banks have the option to participate in any borrowing request by us in excess of the commitment amount ($750 million), up to the borrowing base limit ($900 million), although the banks are not obligated to fund any amount in excess of the commitment amount.

The bank credit facility is secured by substantially all of our producing oil and natural gas properties, and contains several restrictions including, among others: (i) a prohibition on the payment of dividends, (ii) a requirement to maintain positive working capital, as defined, (iii) a minimum interest coverage test, and (iv) a prohibition of most debt and corporate guarantees. Additionally, there is a limitation on the aggregate amount of forecasted production that can be economically hedged with oil or natural gas derivative contracts. We were in compliance with all of our bank covenants as of December 31, 2009. Borrowings under the credit facility are generally in tranches that can have maturities up to one year. Interest on any borrowings is based on the Prime Rate or LIBOR rate plus an applicable margin as determined by the borrowings outstanding. The facility matures in September 2011.

As of December 31, 2009, we had $125 million of outstanding borrowings under the facility and $10.5 million in letters of credit secured by the facility. The weighted average interest rate on these outstanding borrowings was 1.49% at December 31, 2009. The next scheduled redetermination of the borrowing base will be as of April 1, 2010, based on December 31, 2009 assets and proved reserves. Our bank debt borrowing base is adjusted at the banks' discretion and is based in part upon external factors over which we have no control. If our borrowing base were to be less than our outstanding borrowings under the facility, we will be required to repay the deficit over a period of six months.

Newly Committed Bank Revolving Credit Agreement

On November 1, 2009, Denbury and Encore Acquisition Company announced they had entered into a definitive merger agreement pursuant to which Denbury will acquire Encore in a stock and cash transaction. In November 2009, we received commitments for a new $1.6 billion, 4-year revolving credit facility. (See Note 15, "Subsequent Events").

Indebtedness Repayment Schedule

At December 31, 2009, our indebtedness, excluding the discount and premium on our senior subordinated debt, is repayable over the next five years and thereafter as follows:

In thousands	
2010	**$ 5,308**
2011	**132,449**
2012	**7,792**
2013	**233,203**
2014	**9,158**
Thereafter	**945,008**
Total indebtedness	**$1,332,918**

NOTE 7. INCOME TAXES

Our income tax provision (benefit) is as follows:

	Year Ended December 31,		
In thousands	2009	2008	2007
Current income tax expense (benefit)			
Federal	**$ 7,090**	**$ 32,475**	**$ 21,948**
State	**(2,479)**	**8,337**	**8,126**
Total current income tax expense	**4,611**	**40,812**	**30,074**
Deferred income tax expense (benefit)			
Federal	**(50,457)**	**184,630**	**113,868**
State	**(1,187)**	**10,390**	**(3,675)**
Total deferred income tax expense (benefit)	**(51,644)**	**195,020**	**110,193**
Total income tax expense (benefit)	**$(47,033)**	**$235,832**	**$140,267**

At December 31, 2009, we had tax effected state net operating loss carryforwards ("NOLs") totaling $4.4 million and an estimated $38.9 million of enhanced oil recovery credits to carry forward related to our tertiary operations. Our state NOLs expire in 2024. Our enhanced oil recovery credits will begin to expire in 2024.

During the third quarter of 2008, we obtained approval from the Internal Revenue Service ("IRS") to change our method of tax accounting for certain assets used in our tertiary oilfield recovery operations. Previously, we had capitalized and depreciated these costs, but now we can deduct these costs once the assets are placed into service. As a result, we expect to receive tax refunds of approximately $10.6 million for tax years through 2007, along with other tax benefits, and we have reduced our current income tax expense and increased our deferred income tax expense in 2008 to adjust for the impact of this change. This change is not expected to have a significant impact on our overall tax rate; however, it will allow for a quicker deduction of costs for tax purposes.

Deferred income taxes relate to temporary differences based on tax laws and statutory rates in effect at the December 31, 2009 and 2008 balance sheet dates. We believe that we will be able to realize all of our deferred tax assets at December 31, 2009, and therefore have provided no valuation allowance against our deferred tax assets.

At December 31, 2009 and 2008, our deferred tax assets and liabilities were as follows:

In thousands	December 31, 2009	December 31, 2008
Deferred tax assets:		
Loss carryforwards – state	$ 4,394	$ 152
Tax credit carryover	32,156	32,156
Derivative contracts	47,056	—
Enhanced oil recovery credit carryforwards	38,929	43,772
Stock based compensation	23,840	16,216
Other	6,150	—
Total deferred tax assets	152,525	92,296
Deferred tax liabilities:		
Property and equipment	(619,621)	(520,455)
Derivative contracts	—	(91,080)
Other	(2,099)	(2,995)
Total deferred tax liabilities	(621,720)	(614,530)
Total net deferred tax liability	$(469,195)	$(522,234)

Our income tax provision varies from the amount that would result from applying the federal statutory income tax rate to income before income taxes as follows:

In thousands	Year Ended December 31, 2009	2008	2007
Income tax provision (benefit) calculated using the federal statutory income tax rate	$(42,765)	$218,479	$137,695
State income taxes	(3,666)	18,865	11,536
Estimated statutory rate change	—	—	(7,351)
Other	(602)	(1,512)	(1,613)
Total income tax expense (benefit)	$(47,033)	$235,832	$140,267

Uncertain Tax Positions

We adopted the new accounting guidance within the "Income Taxes" topic of the FASC as of January 1, 2007. As a result of the implementation, we determined that approximately $4.0 million of tax benefits previously recognized were considered uncertain tax positions, as the timing of these deductions may not be sustained upon examination by taxing authorities. As such, upon adoption, we recorded income taxes payable of $4.3 million (including $0.3 million in estimated interest) which was offset by a corresponding reduction of the deferred tax liability of $4.1 million for the tax position that we believe will ultimately be sustained. At December 31, 2009, the total amount of unrecognized tax benefits was $1.0 million, exclusive of interest.

There was no cumulative adjustment made to the opening balance of retained earnings at January 1, 2007. Our uncertain tax positions relate primarily to timing differences, and we do not believe any of such uncertain tax positions will materially impact our effective tax rate in future periods. The amount of unrecognized tax benefits is expected to change over the next 12 months, however, such change is not expected to have a material impact on our results of operations or financial position.

We file consolidated and separate income tax returns in the U.S. federal jurisdiction and in many state jurisdictions. We are currently under examination by the IRS for the 2006, 2007 and 2008 tax years. The IRS concluded its examination of our 2004 tax year during the third quarter of 2007 and concluded its examination of our 2005 tax year during the second quarter of 2008. The state of Mississippi concluded its audit of tax years 1998 through 2000 during the third quarter of 2007 and is currently examining years 2001 through 2004. None of the concluded examinations by the Internal Revenue Service or the state of Mississippi resulted in any material assessments. As a result of the examinations concluded during 2007 and 2008, we decreased our total amount of unrecognized tax benefits from $4.5 million at January 1, 2007, to $3.5 million at December 31, 2007, and to $1.0 million at December 31, 2008. These adjustments are all related to temporary timing differences and did not have any impact on our effective tax rate. We have not paid any significant interest or penalties associated with our income taxes, but classify both interest expense and penalties as part of our income tax expense.

NOTE 8. STOCKHOLDERS' EQUITY

Authorized

We are authorized to issue 600 million shares of common stock, par value $.001 per share, and 25 million shares of preferred stock, par value $.001 per share. The preferred shares may be issued in one or more series with rights and conditions determined by the Board of Directors.

Stock Split

On November 19, 2007, stockholders of Denbury Resources Inc. approved an amendment to our Restated Certificate of Incorporation to increase the number of shares of our authorized common stock from 250,000,000 shares to 600,000,000 shares and to split our common stock on a 2-for-1 basis. Stockholders of record on December 5, 2007, received one additional share of Denbury common stock for each share of common stock held at that time.

Information pertaining to shares and earnings per share has been retroactively adjusted in the accompanying financial statements and related notes thereto to reflect the stock splits, except for the share amounts included on our Consolidated Balance Sheets and Consolidated Statements of Changes in Stockholders' Equity, which reflect the actual shares outstanding at each period end.

Stock Issuance

In December 2009, the Company issued 11,620,000 shares of common stock to Wapiti in conjunction with our purchase of oil and gas assets in the Conroe Field (see Note 2, "Acquisitions and Divestitures").

Stock Repurchases

In 2007, 2008 and 2009, all of our share repurchases were from employees of Denbury that delivered shares to the Company to satisfy their minimum tax withholding requirements as provided for under Denbury's 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 8,900,000 shares of common stock. As of December 31, 2009, there were 1,447,342 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 Denbury matches 75% of their contribution. The combined funds are used to purchase previously unissued Denbury common stock or treasury stock purchased by the Company in the open market for that purpose, in either case, based on the market value of Denbury's common stock at the end of each quarter. We recognize compensation expense for the 75% company match portion, which totaled $3.1 million, $2.7 million and $2.2 million for the years ended December 31, 2009, 2008 and 2007, respectively. This plan is administered by the Compensation Committee of Denbury's Board of Directors.

401(k) Plan

Denbury offers a 401(k) plan to which employees may contribute tax deferred earnings subject to Internal Revenue Service limitations. Effective January 1, 2008, Denbury increased its match to 100% of an employee's contribution, up to 6% of compensation, as defined by the plan. Previously, up to 3% of an employee's compensation was matched by Denbury at 100%, and an employee's contribution between 3% and 6% of compensation was matched by Denbury at 50%. Denbury's match is vested immediately. During 2009, 2008 and 2007, Denbury's matching contributions were approximately $4.0 million, $3.3 million and $2.2 million, respectively, to the 401(k) Plan.

NOTE 9. STOCK COMPENSATION PLANS

Stock Incentive Plans

Denbury has two stock compensation plans. The first plan has been in existence since 1995 (the "1995 Plan") and expired in August 2005 (although options granted under the 1995 Plan prior to that time can remain outstanding for up to 10 years). The 1995 Plan only provided for the issuance of stock options, and in January 2005, we issued stock options under the 1995 Plan that utilized substantially all of the remaining authorized shares. The second plan, the 2004 Omnibus Stock and Incentive Plan (the "2004 Plan"), has a 10-year term and was approved by the stockholders in May 2004. In May 2007, shareholders approved an increase to the number of shares that may be used under our 2004 Plan, from 10.0 million to 14.0 million shares. In May 2009, the shareholders approved an additional increase from 14.0 million to 21.5 million shares. The 2004 Plan provides for the issuance of incentive and non-qualified stock options, restricted stock awards, stock appreciation rights ("SARs") settled in stock, and performance awards that may be issued to officers, employees, directors and consultants. Awards covering a total of 21.5 million shares of common stock are authorized for issuance pursuant to the 2004 Plan, of which awards covering no more than 14.2 million shares may be issued in the form of restricted stock or performance vesting awards. At December 31, 2009, a total of 7,565,963 shares were available for future issuance of awards, of which only 7,348,042 shares may be in the form of restricted stock or performance vesting awards.

Denbury has historically granted incentive and non-qualified stock options to its employees. Effective January 1, 2006, we completely replaced the use of stock options for employees with SARs settled in stock, as SARs are less dilutive to our stockholders while providing an employee with essentially the same economic benefits as stock options. The stock options and SARs generally become exercisable over a four-year vesting period with the specific terms of vesting determined at the time of grant based on guidelines established by the Board of Directors. The stock options and SARs expire over terms not to exceed 10 years from the date of grant, 90 days after termination of employment, and 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. The plan is administered by the Compensation Committee of Denbury's Board of Directors.

In 2004, Denbury began the use of restricted stock awards for its officers and independent directors, all granted under the 2004 Plan. The holders of these shares have all of 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. With respect to the restricted stock granted to officers of Denbury in 2004, the vesting restrictions on those shares are as follows: i) 65% of the awards vest 20% per year over five years, and ii) 35% of the awards vest upon retirement, as defined in the 2004 Plan. On January 30, 2009, the Board of Directors modified the vesting provisions for the 35% of the awards that would vest upon retirement to now vest ratably each January 31 (beginning January 31, 2009) until the final vesting on the retirement eligibility date.

Total stock-based compensation expense was $21.9 million, $14.1 million and $10.6 million for the years ended December 31, 2009, 2008 and 2007, respectively. Part of this expense, $1.4 million in 2009, $1.4 million in 2008 and $1.5 million in 2007, was included in "Lease operating expenses" for stock compensation expense associated with our field employees, and the remaining amount recognized in "General and administrative expenses" in the Consolidated Statements of Operations. The total income tax benefit recognized in the Consolidated Statements of Operations for share-based compensation arrangements was $8.7 million, $5.3 million and $4.1 million for the years ended December 31, 2009, 2008 and 2007, respectively. Share-based compensation associated with our employees involved in exploration and drilling activities of $2.5 million, $2.2 million and $1.6 million for the years ended December 31, 2009, 2008 and 2007, respectively, has been capitalized as part of "Oil and natural gas properties" in the Consolidated Balance Sheets.

Stock Options and SARs

The fair value of each SAR award is estimated on the date of grant using the Black-Scholes option pricing model with the assumptions noted in the following table. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the time of grant. The expected life of stock options and SARs granted was derived from examination of our historical option grants and subsequent exercises. The contractual terms (4-year cliff vesting and 4-year graded vesting) are evaluated separately for the expected life, as the exercise behavior for each is different. Expected volatilities are based on the historical volatility of our stock. Implied volatility was not used in this analysis as our tradable call option terms are short and the trading volume is low. Our dividend yield is zero, as Denbury does not pay a dividend.

Beginning in 2009, SARs granted have a term of 7 years as compared to 10 years for grants in prior periods. Additionally, these SARs were issued with a graded vesting as compared to a combination of cliff and graded vesting in prior periods. Both of these changes resulted in a reduced expected term as compared to awards previously issued.

	2009	2008	2007
Weighted average fair value of SARs granted	**$6.40**	**$11.91**	**$6.90**
Risk free interest rate	**1.58%**	**3.29%**	**4.54%**
Expected life	**3.9 to 4.7 years**	**4.5 to 6.2 years**	**4.6 to 6.4 years**
Expected volatility	**60.1%**	**38.1%**	**38.3%**
Dividend yield	**—**	**—**	**—**

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

	Year Ended December 31,					
	2009		2008		2007	
	Number of Options	Weighted Average Price	Number of Options	Weighted Average Price	Number of Options	Weighted Average Price
Outstanding at beginning of year	**9,514,999**	**$ 9.32**	**11,463,285**	**$ 6.28**	**14,964,920**	**$ 4.96**
Granted	**2,883,311**	**13.23**	**1,042,810**	**29.45**	**873,649**	**16.34**
Exercised	**(1,315,535)**	**4.33**	**(2,612,134)**	**3.36**	**(4,054,844)**	**3.44**
Forfeited	**(318,820)**	**16.36**	**(378,962)**	**13.80**	**(320,440)**	**7.90**
Outstanding at end of year	**10,763,955**	**10.77**	**9,514,999**	**9.32**	**11,463,285**	**6.28**
Exercisable at end of year	**6,087,019**	**$ 6.48**	**4,593,407**	**$ 4.55**	**3,969,466**	**$ 3.26**

The total intrinsic value of stock options and SARs exercised during the years ended December 31, 2009, 2008 and 2007, was approximately $14.8 million, $65.8 million and $60.3 million, respectively. The total grant-date fair value of stock options and SARs vested during the years ended December 31, 2009, 2008 and 2007, was approximately $10.1 million, $7.2 million and $6.8 million, respectively. The aggregate intrinsic value of stock options and SARs outstanding at December 31, 2009, was approximately $59.2 million, and these options and SARs have a weighted-average remaining contractual life of 5.3 years. The aggregate intrinsic value of options and SARs exercisable at December 31, 2009, was approximately $52.8 million, and these stock options and SARs have a weighted-average remaining contractual life of 4.3 years.

A summary of the status of our non-vested stock options and SARs as of December 31, 2009, and the changes during the year ended December 31, 2009, is presented below:

Non-Vested Stock Options and SARs	Shares	Weighted Average Grant-Date Fair Value
Non-vested at January 1, 2009	**4,921,592**	**$ 5.87**
Granted	**2,883,311**	**6.40**
Vested	**(2,809,147)**	**3.61**
Forfeited	**(318,820)**	**7.27**
Non-vested at December 31, 2009	**4,676,936**	**7.45**

As of December 31, 2009, there was $18.8 million of total compensation cost to be recognized in future periods related to non-vested stock option and SAR share-based compensation arrangements. The cost is expected to be recognized over a weighted-average period of 2.5 years. Cash received from stock option exercises under share-based payment arrangements for the years ended December 31, 2009, 2008 and 2007, was $5.7 million, $7.7 million and $13.1 million, respectively. The tax benefit realized from the exercises of stock options and SARs totaled $3.1 million for 2009, $18.9 million for 2008, and $18.7 million for 2007.

Restricted Stock

As of December 31, 2009, we had issued 5,900,134 shares of restricted stock (net of forfeited shares) pursuant to the 2004 Plan and have recorded deferred compensation expense of $50.0 million, the fair market value of the shares on the grant dates, net of estimated forfeitures of $6.7 million. This expense is amortized over the applicable five-year, four-year, or retirement date vesting periods. As of December 31, 2009, there was $16.8 million of unrecognized compensation expense related to non-vested restricted stock grants. This unrecognized compensation cost is expected to be recognized over a weighted-average period of 3.57 years.

A summary of the status of our non-vested restricted stock grants and the changes during the year ended December 31, 2009, is presented below:

Non-Vested Restricted Stock Grants	Shares	Weighted Average Grant-Date Fair Value
Non-vested at January 1, 2009	2,210,683	$10.52
Granted	1,032,896	13.34
Vested	(672,732)	7.12
Forfeited	(63,849)	22.42
Non-vested at December 31, 2009	2,506,998	12.29

The total vesting date fair value of restricted stock vested during the years ended December 31, 2009, 2008 and 2007 was $10.0 million, $12.3 million and $10.7 million, respectively.

Performance Equity Awards

Beginning in 2007, the Board of Directors has awarded an annual grant of performance equity awards to the officers of Denbury. These performance-based shares vest over a 1.25 to 3.25 year period. The number of performance-based shares that will be earned (and eligible to vest) during the performance period will depend on the Company's level of success in achieving four specifically identified performance targets. Generally, one-half of the shares earnable under the performance-based shares 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 designated minimum levels for all performance targets, no performance-based shares will be earned. Any portion of the performance shares that are not earned by the end of the three-year measurement period will be forfeited. In certain change of control events, one-half (i.e., the target level amount) of the performance-based shares would vest.

During 2009, we granted 293,571 shares of performance-based equity awards (at the 100% targeted vesting level) to the Company's executive officers with an average grant date fair value of $12.97 per share. The aggregate number of performance-based equity awards outstanding at December 31, 2009 was 475,912 (at the 100% targeted vesting level, less actual forfeitures). The actual number of shares to be delivered pursuant to the performance-based awards could range from zero to 200% (951,824) of the stated 100% targeted amount. The Company recognizes compensation expense when it becomes probable that the performance criteria specified in the plan will be achieved. We currently estimate a targeted vesting level of 110%, 100% and 120% for the 2009, 2008 and 2007 performance grants, respectively. During the years ended December 31, 2009, 2008, 2007, we recorded $4.7 million, $1.2 million and $0.4 million, respectively, of expense in "General and administrative expenses" in our Consolidated Statements of Operations for these performance-based awards.

NOTE 10. 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 and 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 "Commodity derivative 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. Historically, we have hedged up to 80% of our anticipated production for the following year to provide us with a reasonably certain amount of cash flow to cover most of our budgeted exploration and development expenditures without incurring significant debt. Also, in light of the recently announced acquisition of Encore, and our desire to protect our cash flows given the increased debt levels we expect in connection with the acquisition, in November 2009 we entered into costless collar crude oil contracts covering 25,000 Bbls/d during 2011.

All of the mark-to-market valuations used for our oil and natural gas derivative contracts are provided by external sources and are based on prices that are actively quoted. 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 derivative contracts are with parties that are lenders under our Senior Bank Loan. We have included an estimate of nonperformance risk in the fair value measurement of our derivative contracts as required by FASC guidance on fair value. At December 31, 2009 and 2008, the fair value of our derivative contracts was reduced by $0.8 million and $3.7 million, respectively, for estimated nonperformance risk.

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

	Year Ended December 31,		
In thousands	2009	2008	2007
Receipt (payment) on settlements of derivative contracts – oil	**$ 146,734**	**$ (30,969)**	**$ (9,833)**
Receipt (payment) on settlements of derivative contracts – gas	**—**	**(26,584)**	**30,313**
Fair value adjustments to derivative contracts – income (expense)	**(382,960)**	**257,606**	**(39,077)**
Commodity derivative income (expense)	**$(236,226)**	**$ 200,053**	**$(18,597)**

Fair Value of Commodity Derivative Contracts Not Classified as Hedging Instruments:

	NYMEX Contract Prices Per Unit				Estimated Fair Value Asset (Liability) December 31,	
			Collar Prices			
Type of Contract and Period	Bbls/d	Swap Price	Floor	Ceiling	2009	2008
					In thousands	
Crude Oil Contracts:						
2009 Oil Collars	**30,000**	**$ —**	**$75.00**	**$115.00**	**$ —**	**$249,746**
Q1 2010 Oil Swaps						
Jan 2010–Mar 2010	**6,667**	**52.50**	**—**	**—**	**(16,552)**	**—**
Jan 2010–Mar 2010	**3,333**	**52.20**	**—**	**—**	**(8,365)**	**—**
Jan 2010–Mar 2010	**5,000**	**50.90**	**—**	**—**	**(13,131)**	**—**
Jan 2010–Mar 2010	**5,000**	**51.45**	**—**	**—**	**(12,884)**	**—**
Jan 2010–Mar 2010	**5,000**	**52.10**	**—**	**—**	**(12,593)**	**—**
					(63,525)	**—**
Q1 2010 Oil Collars						
Jan 2010–Mar 2010	**3,000**	**—**	**70.00**	**92.00**	**53**	**—**
Jan 2010–Mar 2010	**2,000**	**—**	**70.00**	**92.40**	**42**	**—**
					95	**—**
Q2 2010 Oil Collars						
Apr 2010–Jun 2010	**5,000**	**—**	**50.00**	**76.40**	**(4,454)**	**—**
Apr 2010–Jun 2010	**10,000**	**—**	**50.00**	**73.15**	**(10,858)**	**—**
Apr 2010–Jun 2010	**5,000**	**—**	**50.00**	**76.00**	**(4,569)**	**—**
Apr 2010–Jun 2010	**5,000**	**—**	**50.00**	**74.30**	**(5,074)**	**—**
Apr 2010–Jun 2010	**5,000**	**—**	**70.00**	**95.25**	**214**	**—**
					(24,741)	**—**
Q3 2010 Oil Collars						
Jul 2010–Sept 2010	**2,500**	**—**	**55.00**	**80.10**	**(2,176)**	**—**
Jul 2010–Sept 2010	**5,000**	**—**	**55.00**	**80.00**	**(4,378)**	**—**
Jul 2010–Sept 2010	**7,500**	**—**	**60.00**	**80.40**	**(5,894)**	**—**
Jul 2010–Sept 2010	**5,000**	**—**	**60.00**	**81.05**	**(3,768)**	**—**
Jul 2010–Sept 2010	**5,000**	**—**	**55.00**	**80.00**	**(4,378)**	**—**
Jul 2010–Sept 2010	**2,500**	**—**	**70.00**	**96.00**	**(115)**	**—**
Jul 2010–Sept 2010	**2,500**	**—**	**70.00**	**97.00**	**(52)**	**—**
					(20,761)	**—**
Q4 2010 Oil Collars						
Oct 2010–Dec 2010	**5,000**	**—**	**60.00**	**89.70**	**(2,555)**	**—**
Oct 2010–Dec 2010	**5,000**	**—**	**60.00**	**89.50**	**(2,592)**	**—**
Oct 2010–Dec 2010	**5,000**	**—**	**60.00**	**89.00**	**(2,684)**	**—**
Oct 2010–Dec 2010	**5,000**	**—**	**60.00**	**89.50**	**(2,592)**	**—**
Oct 2010–Dec 2010	**5,000**	**—**	**60.00**	**88.75**	**(2,730)**	**—**
Oct 2010–Dec 2010	**2,500**	**—**	**70.00**	**96.00**	**(115)**	**—**
Oct 2010–Dec 2010	**2,500**	**—**	**70.00**	**97.00**	**(52)**	**—**
					(13,320)	**—**

Type of Contract and Period	NYMEX Contract Prices Per Unit				Estimated Fair Value Asset (Liability) December 31,	
			Collar Prices			
	Bbls/d	Swap Price	Floor	Ceiling	2009	2008
					In thousands	
2011 Oil Collars						
Jan 2011–Dec 2011	3,000	—	70.00	101.10	(865)	—
Jan 2011–Dec 2011	2,000	—	70.00	101.55	(487)	—
Jan 2011–Dec 2011	2,500	—	70.00	100.95	(758)	—
Jan 2011–Dec 2011	2,500	—	70.00	102.00	(500)	—
Jan 2011–Dec 2011	2,000	—	70.00	103.00	(211)	—
Jan 2011–Dec 2011	2,000	—	70.00	106.00	310	—
Jan 2011–Dec 2011	1,000	—	70.00	105.50	114	—
Jan 2011–Dec 2011	1,000	—	70.00	101.50	(249)	—
Jan 2011–Dec 2011	2,000	—	70.00	104.00	(31)	—
Jan 2011–Dec 2011	2,000	—	70.00	101.20	(557)	—
Jan 2011–Dec 2011	3,000	—	70.00	102.00	(600)	—
Jan 2011–Dec 2011	2,000	—	70.00	104.65	82	—
					(3,752)	—
				Total Crude Oil Contracts	$(126,004)	$249,746
Natural Gas Contracts:						
2010 Natural Gas Swaps	39,000	$ 5.67	$ —	$ —	$ (1,759)	$ —
					(1,759)	—
2011 Natural Gas Swaps						
Jan 2011–Dec 2011	10,000	6.27	—	—	(244)	—
Jan 2011–Dec 2011	10,000	6.25	—	—	(296)	—
Jan 2011–Dec 2011	7,000	6.16	—	—	(441)	—
					(981)	—
				Total Natural Gas Contracts	$ (2,740)	$ —
				Total Commodity Derivative Contracts	$(128,744)	$249,746

Additional Disclosures about Derivative Instruments:

At December 31, 2009 and 2008, 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,	
		2009	2008
		In thousands	
Derivatives not designated as hedging instruments:			
Derivative Asset			
Crude Oil contracts	Derivative assets – current	$ 309	$249,746
Crude Oil contracts	Other assets	506	—
Derivative Liability			
Crude Oil contracts	Derivative liabilities – current	(122,561)	—
Natural Gas contracts	Derivative liabilities – current	(1,759)	—
Crude Oil contracts	Derivative liabilities – long-term	(4,258)	—
Natural Gas contracts	Derivative liabilities – long-term	(981)	—
Total derivatives not designated as hedging instruments		$(128,744)	$249,746

For the years ended December 31, 2009, 2008, and 2007, the net effect on income of derivative financial instruments was as follows:

Type of Contract	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Recognized in Income Year Ended December 31, 2009	2008	2007
			In thousands	
Derivatives not designated as hedging instruments:				
Commodity Contracts				
Crude Oil Contracts	**Commodity derivative income (expense)**	**$(229,016)**	**$228,920**	**$(24,310)**
Natural Gas Contracts	**Commodity derivative income (expense)**	**(7,210)**	**(28,867)**	**5,713**
Total derivatives not designated as hedging instruments		**$(236,226)**	**$200,053**	**$(18,597)**

NOTE 11. FAIR VALUE MEASUREMENTS

Fair value is 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 (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. For the years ended December 31, 2009 and 2008, we had no level 1 recurring measurements.

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. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, 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.

Instruments in this category include non-exchange-traded oil and natural gas derivatives such as over-the-counter swaps. We have included an estimate of nonperformance risk in the fair value measurement of our oil and natural gas derivative contracts. We have measured nonperformance risk based upon credit default swaps or credit spreads. At December 31, 2009 and 2008, the fair value of our oil and natural gas derivative contracts was reduced by $0.8 million and $3.7 million, respectively, for estimated nonperformance risk.

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.

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, 2009 and 2008.

	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, 2009				
Assets:				
Oil derivative contracts	$ —	$ 815	$ —	$ 815
Liabilities:				
Oil and natural gas derivative contracts	—	(129,559)	—	(129,559)
Total	$ —	$ (128,744)	$ —	$(128,744)
December 31, 2008				
Assets:				
Oil derivative contracts	$ —	$ 249,746	$ —	$ 249,746
Total	$ —	$ 249,746	$ —	$ 249,746

The following table sets forth the fair value of financial instruments that are not recorded at fair value in our Consolidated Financial Statements.

	December 31, 2009		December 31, 2008	
In thousands	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
9.75% Senior Subordinated Notes due 2016	$399,926	$455,129	$ —	$ —
7.5% Senior Subordinated Notes due 2015	300,513	299,250	300,599	213,000
7.5% Senior Subordinated Notes due 2013	224,369	226,125	224,174	171,000
Senior Bank Loan	125,000	122,500	75,000	64,000

The fair values of our senior subordinated notes are based on quoted market prices. The carrying value of our Senior Bank Loan is approximately fair value based on the fact that it is subject to short-term floating interest rates that approximate the rates available to us for those periods. We adjusted the estimated fair value measurement of our Senior Bank Loan for estimated nonperformance risk. This estimated nonperformance risk totaled approximately $2.5 million and $11.0 million at December 31, 2009 and 2008, respectively, and was determined utilizing industry credit default swaps. 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 12. COMMITMENTS AND CONTINGENCIES

We have operating leases for the rental of equipment, office space and vehicles that totaled $162.2 million, $128.6 million and $143.8 million as of December 31, 2009, 2008 and 2007, respectively. During the last seven years, we entered into lease financing agreements for equipment at certain of our oil and natural gas properties and CO_2 source fields. These lease financings totaled $49.3 million during 2009, $6.1 million during 2008, and $27.1 million during 2007 with associated required monthly payments of approximately $670,000 for the 2009 leases, $56,000 for the 2008 leases, and $257,000 for the 2007 leases. Leases entered into prior to 2006 have seven-year terms, leases entered into in 2006 through 2008 have 10-year terms, and leases entered into in 2009 have five to 10-year terms. Rental expense for operating leases totaled $37.6 million in 2009, $32.3 million in 2008, and $24.6 million in 2007. We have subleased part of the office space where we have operating leases. The cash payments we will receive under these contracts total approximately $0.9 million for 2010 through 2012.

In 2005 and 2006, we entered into three agreements with Genesis to transport crude oil and CO_2. These agreements are accounted for as capital leases and are discussed in detail in Note 3, "Related Party Transactions – Genesis". In 2008, we entered into two transactions with Genesis involving our NEJD Pipeline system and Free State Pipeline, which included a long-term transportation service agreement for the Free State Pipeline and a 20-year financing lease for the NEJD Pipeline system. These two transactions are accounted for as financing leases and are discussed in detail in Note 3, "Related Party Transactions-Genesis".

At December 31, 2009, long-term commitments for these items require the following future minimum rental payments:

In thousands	Pipeline Financing Leases	Capital Leases	Operating Leases
2010	**$ 31,759**	**$ 1,974**	**$ 27,566**
2011	**33,205**	**1,974**	**26,621**
2012	**33,438**	**1,272**	**23,248**
2013	**33,518**	**700**	**20,544**
2014	**33,513**	**673**	**17,145**
Thereafter	**393,623**	**721**	**47,037**
Total minimum lease payments	**559,056**	**7,314**	**$162,161**
Less: Amount representing interest	**(308,436)**	**(1,366)**	
Present value of minimum lease payments	**$ 250,620**	**$ 5,948**	

Long-term contracts require us to deliver CO_2 to our industrial CO_2 customers at various contracted prices, plus we have a CO_2 delivery obligation to Genesis related to three CO_2 volumetric production payments ("VPPs") (see Note 3). Based upon the maximum amounts deliverable as stated in the industrial contracts and the volumetric production payments, we estimate that we may be obligated to deliver up to 433 Bcf of CO_2 to these customers over the next 18 years; however, since the group as a whole has historically purchased less CO_2 than the maximum allowed in their contracts, based on the current level of deliveries, we project that the amount of CO_2 that we will ultimately be required to deliver would likely be reduced to 165 Bcf. The maximum volume required in any given year is approximately 136 MMcf/d. Given the size of our proven CO_2 reserves at December 31, 2009 (approximately 6.3 Tcf before deducting approximately 127.1 Bcf for the three VPPs), our current production capabilities and our projected levels of CO_2 usage for our own tertiary flooding program, we believe that we can meet these contractual delivery obligations.

We currently have long-term commitments to purchase manufactured CO_2 from eight proposed gasification plants: four are in the Gulf Coast region and four are in the Midwest region (Illinois, Indiana and Kentucky area) of the United States. The Midwest plants are not only conditioned on those specific plants being constructed, but also upon Denbury contracting additional volumes of CO_2 for purchase in the general area of the proposed plants that would provide an acceptable economic return on the CO_2 pipeline that we would need to construct to transport these volumes to our existing CO_2 pipeline system. If all of these plants are built, these CO_2 sources are currently anticipated to provide us with aggregate CO_2 volumes of around 1.2 Bcf/d to 1.9 Bcf/d. Due to the current economic conditions, the earliest we would expect any plant to be completed and provide CO_2 would be 2014, and there is some doubt as to whether they will be constructed at all. The base price of CO_2 per Mcf from these CO_2 sources varies by plant and location, but is generally higher than our most recent all-in cost of CO_2 from our natural sources (Jackson Dome) using current oil prices. Prices for CO_2 delivered from these projects are expected to be competitive with the cost of our natural CO_2 after adjusting for our estimates of future prices for our share of potential carbon emissions reduction credits. If all eight plants are built, the aggregate purchase obligation for this CO_2 would be around $280 million per year, assuming a $70 per barrel oil price, before any potential savings from our share of carbon emissions reduction credits. All of the contracts have price adjustments that fluctuate based on the price of oil. Construction has not yet commenced on any of these plants, and their construction is contingent on the satisfactory resolution of various issues, including financing. While it is likely that not every plant currently under contract will be constructed, there are several other plants under consideration that could provide CO_2 to us that would either supplement or replace the CO_2 volumes from the eight proposed plants for which we currently have CO_2 purchase contracts. We are having ongoing discussions with several of these other potential sources. We have invested a total of $13.8 million in preferred stock of one of the proposed plants. All of our investment may later be redeemed, with a return, or converted to equity after construction financing for the project has been obtained. We have recorded our investment in this debt security at cost and classified it as held-to-maturity, since we have the intent and ability to hold it until it is redeemed. The investment is included in "Other assets" in our Consolidated Balance Sheets.

The Encore Merger Agreement contains certain termination rights for both Denbury and Encore, including, among others, if the Merger is not completed by May 31, 2010. In the event of a termination of the Merger Agreement under certain circumstances, Encore may be required to pay Denbury a termination fee of either $60 million or $120 million, or Denbury may be required to pay Encore a termination fee of either $60 million, $120 million or $300 million, in each case depending on the circumstances of the termination. In addition, Encore is obligated to reimburse Denbury for up to $10 million of its expenses related to the Merger if specified termination events occur. In addition, fee letters executed in conjunction with the financing commitment from JP Morgan require Denbury to pay up to approximately $48 million in fees if the Merger is not consummated and the loans do not close.

Denbury is 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 management believes that it has 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.

Litigation

In connection with the Merger, three shareholder lawsuits styled as class actions have been filed against Encore Acquisition Company ("Encore") and its board of directors. The lawsuits are entitled Sanjay Israni, Individually and On Behalf of All Others Similarly Situated vs. Encore Acquisition Company et al. (filed November 4, 2009 in the District Court of Tarrant County, Texas), Teamsters Allied Benefit Funds, Individually and On Behalf of All Others Similarly Situated vs. Encore Acquisition Company et al. (filed November 5, 2009 in the Court of Chancery in the State of Delaware) and Thomas W. Scott, Jr., individually and on behalf of all others similarly situated v. Encore Acquisition Company et al. (filed November 6, 2009 in the District Court of Tarrant County, Texas). The Teamsters and Scott lawsuits also name Denbury as a defendant. The complaints generally allege that (1) Encore's directors breached their fiduciary duties in negotiating and approving the Merger and by administering a sale process that failed to maximize shareholder value and (2) Encore, and, in the case of the Teamsters and Scott complaints, Denbury aided and abetted Encore's directors in breaching their fiduciary duties. The Teamsters complaint also alleges that Encore's directors and executives stand to receive substantial financial benefits if the transaction is consummated on its current terms. The plaintiffs in these lawsuits seek, among other things, to enjoin the Merger and to rescind the Merger Agreement. Encore and Denbury have entered into a Memorandum of Understanding with the plaintiffs in these lawsuits agreeing in principle to the settlement of the lawsuits based upon inclusion in our joint proxy statement/prospectus dated February 5, 2010, mailed to shareholders of Denbury and Encore in connection with their respective shareholder meetings to approve the Merger, of additional disclosures requested by the plaintiffs, and agreeing that the parties to the lawsuits will use best efforts to enter into a definitive settlement agreement, which has not yet occurred pending completion of limited discovery, and to seek court approval for the settlement which would be binding on all Encore shareholders who do not opt-out of the settlement. We currently believe the ultimate outcome of the settlement of these lawsuits will not have a material adverse effect on our financial position, results of operations or cash flows.

A shareholder suit regarding a compensation matter brought as a derivative action on behalf of Denbury against Denbury's board of directors, entitled Harbor Police Retirement System v. Gareth Roberts, et al, in the District Court of Dallas County, Texas, was amended during January 2010 to generally allege breach of the Denbury directors' fiduciary duties based upon the further allegation that the directors approved an unreasonably high purchase price in the Merger. On February 19, 2010, the plaintiff filed a motion for leave to amend its petition to add proxy disclosure claims related to the joint proxy statement/prospectus dated February 5, 2010. The plaintiff seeks monetary damages and equitable relief, and if the motion to amend their petition is granted, to enjoin the Denbury shareholders meeting. A hearing is currently scheduled for March 1, 2010 on various pending motions, including a motion to dismiss the complaint. Denbury believes that its directors have a valid defense to all claims against them, and that the other allegations in this suit are without merit. Denbury and its directors intend to defend this litigation vigorously. We currently believe the ultimate outcome of this lawsuit will not have a material adverse effect on our financial position, results of operations or cash flows.

We are involved in other 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.

NOTE 13. 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. The loss of any purchaser would not be expected to have a material adverse effect upon our operations. For the year ended December 31, 2009, two purchasers accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company LLC (52%) and Hunt Crude Oil Supply Co. (21%). For the year ended December 31, 2008, we had three significant purchasers that each accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company LLC (49%), Hunt Crude Oil Supply Co. (20%) and Crosstex Energy Field Services Inc. (14%). For the year ended December 31, 2007, three purchasers each accounted for 10% or more of our oil and natural gas revenues: Marathon Petroleum Company LLC (43%), Hunt Crude Oil Supply Co. (19%) and Crosstex Energy Field Services Inc. (16%).

Accounts Payable and Accrued Liabilities

	December 31,	
In thousands	2009	2008
Accounts payable	**$ 40,140**	**$ 111,899**
Accrued exploration and development costs	**40,375**	**50,571**
Accrued compensation	**35,292**	**10,746**
Accrued lease operating expense	**14,512**	**10,014**
Accrued interest	**24,214**	**6,780**
Taxes payable	**5,358**	**6,282**
Asset retirement obligations – current	**1,087**	**1,712**
Other	**8,896**	**4,629**
Total	**$169,874**	**$ 202,633**

Supplemental Cash Flow Information

	Year Ended December 31,		
In thousands, except shares	2009	2008	2007
Cash paid for interest, net of amounts capitalized	**$ 20,924**	**$ 26,997**	**$ 27,892**
Cash paid for income taxes	**241**	**70,349**	**10,277**
Interest capitalized	**68,596**	**29,161**	**20,385**
Increase (decrease) in liabilities for capital expenditures	**(76,025)**	**59,183**	**(421)**
Common stock issued pursuant to Conroe Field Acquisition	**168,723**	**—**	**—**
Genesis common units received in lease financing	**—**	**25,000**	**—**
Market value of restricted stock issued	**$ 13,781**	**$ 8,749**	**$ 6,487**
Shares of restricted stock issued	**1,032,896**	**278,973**	**367,108**

NOTE 14. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

Our subordinated debt is fully and unconditionally guaranteed jointly and severally by all of Denbury Resources Inc.'s subsidiaries other than minor subsidiaries, except that with respect to our $225 million of 7.5% Senior Subordinated Notes due 2013, Denbury Resources Inc. and Denbury Onshore, LLC are co-obligors. Except as noted in the foregoing sentence, Denbury Resources Inc. is the sole issuer and Denbury Onshore, LLC is a subsidiary guarantor. The results of our equity interest in Genesis are reflected through the equity method by one of our subsidiaries, Denbury Gathering & Marketing. Each subsidiary guarantor and the subsidiary co-obligor are 100% owned, directly or indirectly, by Denbury Resources Inc. The following is condensed consolidating financial information for Denbury Resources Inc., Denbury Onshore, LLC, and subsidiary guarantors:

Condensed Consolidating Balance Sheets

	December 31, 2009				
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Assets					
Current assets	$ 637,334	$ 253,601	$ 20,718	$ (655,891)	$ 255,762
Property and equipment	—	3,482,310	220,562	—	3,702,872
Investment in subsidiaries (equity method)	1,303,728	23,792	1,299,186	(2,551,689)	75,017
Other assets	746,442	225,938	6,078	(742,131)	236,327
Total assets	$2,687,504	$3,985,641	$1,546,544	$(3,949,711)	$4,269,978
Liabilities and Stockholders' Equity					
Current liabilities	$ 14,827	$ 795,486	$ 239,368	$ (655,891)	$ 393,790
Long-term liabilities	700,440	1,942,194	3,448	(742,131)	1,903,951
Stockholders' equity	1,972,237	1,247,961	1,303,728	(2,551,689)	1,972,237
Total liabilities and stockholders' equity	$2,687,504	$3,985,641	$1,546,544	$(3,949,711)	$4,269,978

	December 31, 2008				
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Assets					
Current assets	$ 458,051	$ 408,940	$ 14,992	$ (466,784)	$ 415,199
Property and equipment	—	2,973,947	28,250	—	3,002,197
Investment in subsidiaries (equity method)	1,371,347	24,901	1,368,759	(2,685,003)	80,004
Other assets	312,239	89,471	899	(310,335)	92,274
Total assets	$2,141,637	$3,497,259	$1,412,900	$(3,462,122)	$3,589,674
Liabilities and Stockholders' Equity					
Current liabilities	$ 970	$ 810,476	$ 41,405	$ (466,784)	$ 386,067
Long-term liabilities	300,599	1,373,127	148	(310,335)	1,363,539
Stockholders' equity	1,840,068	1,313,656	1,371,347	(2,685,003)	1,840,068
Total liabilities and stockholders' equity	$2,141,637	$3,497,259	$1,412,900	$(3,462,122)	$3,589,674

Condensed Consolidating Statements of Operations

	Year Ended December 31, 2009				
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 58,984	$ 882,492	$ 1	$ (58,984)	$ 882,493
Expenses	64,348	996,138	9,837	(58,984)	1,011,339
Loss before the following:	(5,364)	(113,646)	(9,836)	—	(128,846)
Equity in net earnings of subsidiaries	(67,689)	528	(59,635)	133,453	6,657
Income before income taxes	(73,053)	(113,118)	(69,471)	133,453	(122,189)
Income tax provision (benefit)	2,103	(47,354)	(1,782)	—	(47,033)
Net loss	$(75,156)	$ (65,764)	$(67,689)	$133,453	$ (75,156)

In thousands	Year Ended December 31, 2008 Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 22,500	$1,365,658	$ 44	$ (22,500)	$1,365,702
Expenses	22,982	743,033	3,313	(22,500)	746,828
Income (loss) before the following:	(482)	622,625	(3,269)	—	618,874
Equity in net earnings of subsidiaries	408,393	666	412,100	(815,805)	5,354
Income before income taxes	407,911	623,291	408,831	(815,805)	624,228
Income tax provision	19,515	215,879	438	—	235,832
Net income	$388,396	$ 407,412	$408,393	$(815,805)	$ 388,396

In thousands	Year Ended December 31, 2007 Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 19,594	$972,992	$ 68	$ (19,594)	$973,060
Expenses	20,046	574,134	3,950	(19,594)	578,536
Income (loss) before the following:	(452)	398,858	(3,882)	—	394,524
Equity in net earnings of subsidiaries	253,970	—	256,443	(511,523)	(1,110)
Income before income taxes	253,518	398,858	252,561	(511,523)	393,414
Income tax provision (benefit)	371	141,305	(1,409)	—	140,267
Net income	$253,147	$257,553	$253,970	$(511,523)	$253,147

Condensed Consolidating Statements of Cash Flows

Denbury Resources Inc. (Parent) has no independent assets or operations. Denbury Onshore, LLC is our operating subsidiary. Cash flow activity of Denbury Resources Inc. consists of intercompany loans between Denbury Resources Inc. and Denbury Onshore, LLC to service the parent company issued debt. This intercompany cash flow activity is eliminated in consolidation. Cash flow activity of Denbury Onshore, LLC combined with the other guarantor subsidiaries is presented in our Consolidated Statements of Cash Flows.

In thousands	Year Ended December 31, 2009 Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Cash flow from operations	$ —	$ 530,460	$139	$ —	$ 530,599
Cash flow from investing activities	(412,837)	(969,714)	—	412,837	(969,714)
Cash flow from financing activities	412,837	442,637	—	(412,837)	442,637
Net increase in cash	—	3,383	139	—	3,522
Cash, beginning of period	24	16,898	147	—	17,069
Cash, end of period	$ 24	$ 20,281	$286	$ —	$ 20,591

In thousands	Year Ended December 31, 2008 Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Cash flow from operations	$ (10)	$ 776,112	$(1,583)	$ —	$ 774,519
Cash flow from investing activities	(29,874)	(994,659)	—	29,874	(994,659)
Cash flow from financing activities	29,874	177,102	—	(29,874)	177,102
Net decrease in cash	(10)	(41,445)	(1,583)	—	(43,038)
Cash, beginning of period	34	58,343	1,730	—	60,107
Cash, end of period	$ 24	$ 16,898	$ 147	$ —	$ 17,069

In thousands	Year Ended December 31, 2007 Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Cash flow from operations	$ 33	$ 570,098	$ 83	$ —	$ 570,214
Cash flow from investing activities	(183,204)	(762,513)	—	183,204	(762,513)
Cash flow from financing activities	183,204	198,533	—	(183,204)	198,533
Net increase in cash	33	6,118	83	—	6,234
Cash, beginning of period	1	52,225	1,647	—	53,873
Cash, end of period	$ 34	$ 58,343	$1,730	$ —	$ 60,107

NOTE 15. SUBSEQUENT EVENTS (UNAUDITED)

ENCORE MERGER

On October 31, 2009, the Company entered into a definitive merger agreement providing for Encore Acquisition Company ("Encore") to merge with and into the Company. Under the terms of the definitive agreement, Encore stockholders will receive $50.00 per share for each share of Encore common stock, comprised of $15.00 in cash and $35.00 in Denbury common stock subject to both an election feature and a collar mechanism on the stock portion of the consideration. Consummation of the merger is subject to shareholder approval as well as other customary conditions. Denbury and Encore each scheduled March 9, 2010 as the date for their respective upcoming special stockholder meetings, at which time shareholders will vote on, among other items, the merger of Encore with and into Denbury.

NEW SENIOR SUBORDINATED NOTES

On February 10, 2010, Denbury issued $1.0 billion of 8.25% Senior Subordinated Notes due 2020 ("2020 Notes"). The 2020 Notes, which carry a coupon rate of 8.25%, were sold at par. The net proceeds of approximately $980 million were deposited into escrow. If the merger with Encore does not occur on or prior to May 31, 2010, or if the merger agreement is terminated at any time, we will be required to redeem the 8.25% Senior Subordinated Notes at 100% of par, plus accrued and unpaid interest. After the merger, to the extent that fewer than $600.0 million principal amount of Encore senior subordinated notes are tendered for repurchase by August 1, 2010, we will be required to redeem an amount of the 2020 Notes equal to such shortfall.

The 2020 Notes mature on February 15, 2020, and interest is payable on February 15 and August 15 of each year, beginning August 15, 2010. We may redeem the 2020 Notes in whole or in part at our option beginning February 15, 2015, at the following redemption prices: 104.125% after February 15, 2015, 102.75% after February 15, 2016, 101.375% after February 15, 2017, and 100% after February 15, 2018. Prior to February 15, 2013, we may at our option redeem up to an aggregate of 35% of the principal amount of the 2020 Notes at a price of 108.25% with the proceeds of certain equity offerings. In addition, at any time prior to February 15, 2015, we may redeem 100% of the principal amount of the 2020 Notes at a price equal to 100% of the principal amount plus a "make whole" premium and accrued and unpaid interest. The indenture 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 significant subsidiaries fully and unconditionally guarantee this debt.

NEWLY COMMITTED CREDIT FACILITY

On October 31, 2009, Denbury received a financing commitment from JP Morgan, subject to customary conditions, to underwrite a new senior secured revolving credit facility. The newly committed credit facility, together with the proceeds from the 8.25% Senior Subordinated Notes, will be used to fund a portion of the cash consideration for the merger with Encore, repay amounts outstanding under Denbury's existing $750 million revolving credit facility, potentially retire and replace a portion of Encore's outstanding senior subordinated notes and to pay other merger-related expenses. The aggregate commitment of the senior secured lenders is $1.6 billion and the term of the newly committed credit facility is four years.

SALE OF GENERAL PARTNER OWNERSHIP IN GENESIS

On February 5, 2010, we sold our interest in Genesis Energy, LLC to an affiliate of Quintana Capital Group L.P. ("Quintana") for net proceeds of approximately $82 million, calculated as $100 million less adjustments including those related to Genesis management incentive compensation and other selling costs. This sale gives Quintana control of Genesis' general partner. We continue to own approximately 10% of the outstanding common units of Genesis, for which a resale registration statement was filed in January 2010.

EQUITY AWARD GRANT

On January 4, 2010, we granted equity incentive awards to our employees under the 2004 Plan. The grant included 659,509 shares of restricted stock valued at $15.63 per share and 1,780,276 SARs with an exercise price of $15.63 and a weighted average grant date fair value of $8.22 per unit. The awards generally vest 25% per year over a four-year period.

NOTE 16. SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES (UNAUDITED)

Costs Incurred

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

The Company capitalizes interest on unevaluated oil and gas properties that have ongoing development activities. Included in the costs incurred below are capitalized interest of $14.3 million in 2009, $17.6 million in 2008 and $18.3 million in 2007. 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 $11.2 million in 2009, $5.8 million in 2008 and $7.5 million in 2007 (see Note 4, "Asset Retirement Obligations").

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

	Year Ended December 31,		
In thousands	2009	2008	2007
Property acquisitions:			
Proved	**$ 585,637**	**$ 32,781**	**$ 15,531**
Unevaluated	**104,772**	**16,129**	**60,079**
Exploration	**4,635**	**5,710**	**42,726**
Development	**292,545**	**575,947**	**553,315**
Total costs incurred[(1)]	**$ 987,589**	**$ 630,567**	**$ 671,651**

(1) Capitalized general and administrative costs that directly relate to exploration and development activities were $14.0 million, $12.5 million and $10.3 million for the years ended December 31, 2009, 2008, 2007, respectively.

Oil and Natural Gas Operating Results

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

	Year Ended December 31,		
In thousands, except per BOE data	2009	2008	2007
Oil, natural gas and related product sales	$866,709	$1,347,010	$952,788
Lease operating costs	326,132	307,550	230,932
Production taxes and marketing expenses	42,484	63,752	49,091
Depletion, depreciation and amortization	206,999	195,839	177,333
CO_2 depletion, depreciation and amortization [1]	29,076	16,771	9,403
Write-down of oil and natural gas properties	—	226,000	—
Commodity derivative expense (income)	236,226	(200,053)	18,597
Net operating income	25,792	737,151	467,432
Income tax provision	9,927	278,643	177,624
Results of operations from oil and natural gas producing activities	$ 15,865	$ 458,508	$289,808
Depletion, depreciation and amortization per BOE	$ 13.39	$ 12.54	$ 11.60

(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

Effective December 31, 2009, the Company adopted new guidance issued by the SEC related to the quantification of oil and natural gas reserves (see Note 1, "Significant Accounting Policies – Recently Adopted Accounting Pronouncements"). The SEC's new guidance enhances disclosures related to oil and natural gas reserves, permits the use of new technology to quantify reserves, and adjusts the pricing used to determine proved reserves. Estimates of reserves as of year-end 2009 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month period ended December 31, 2009. Estimates of reserves as of year-end 2007 and 2008 were prepared using constant prices and costs in accordance with previous guidelines of the Securities and Exchange Commission based on hydrocarbon prices received on a field-by-field basis as of December 31st of each year. The adoption of the new guidance did not have a material impact on Denbury's estimate of proved reserves at December 31, 2009. The standardized measure of discounted future net cash flows as of December 31, 2009, reflects a decrease of $1.1 billion as a result of the change in sales prices resulting from new pricing guidelines.

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. 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. All of our reserves are located in the United States.

Estimated Quantities of Reserves

	Year Ended December 31,					
	2009		2008		2007	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)
Balance at beginning of year	179,126	427,955	134,978	358,608	126,185	288,826
Revisions of previous estimates	(69)	(1,298)	1,348	10,291	(1,601)	1,478
Revisions due to price changes	4,557	(2,079)	(13,320)	(2,915)	1,538	(355)
Extensions and discoveries	334	11,785	5,037	107,020	6,887	131,451
Improved recovery[1]	13,875	—	59,317	—	12,376	—
Production	(13,495)	(24,764)	(11,505)	(32,736)	(10,193)	(35,456)
Acquisition of minerals in place	28,379	2,317	3,653	79	405	1,935
Sales of minerals in place	(19,828)	(325,941)	(382)	(12,392)	(619)	(29,271)
Balance at end of year	192,879	87,975	179,126	427,955	134,978	358,608
Proved Developed Reserves:						
Balance at beginning of year	96,746	298,114	97,005	226,271	83,703	176,648
Balance at end of year	116,192	69,513	96,746	298,114	97,005	226,271

(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.

Acquisitions of minerals in place during 2009 were primarily from the Conroe Field and Hastings Field acquisitions. The sales of minerals in place during 2009 were primarily due to the sale of our Barnett Shale assets. We added 17.6 MMBbls of tertiary related proved oil reserves during 2009, primarily initial proved tertiary oil reserves at Cranfield Field in Phase 4, plus additional reserves at Tinsley, Heidelberg and Eucutta Fields. 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.

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, 2009 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. Prior to 2009, future cash inflows were estimated by applying year-end prices 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 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,		
	2009	2008	2007
Oil (NYMEX)	$61.18	$44.60	$95.98
Natural Gas (Henry Hub)	3.87	5.71	6.80

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. Future income taxes were computed by applying the statutory tax rate to the excess of pre-tax 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	2009	2008	2007
Future cash inflows	**$11,579,159**	**$ 9,024,224**	**$14,082,865**
Future production costs	**(5,034,393)**	**(4,039,898)**	**(3,687,197)**
Future development costs	**(836,455)**	**(944,716)**	**(605,638)**
Future income taxes	**(1,257,844)**	**(1,071,939)**	**(3,283,702)**
Future net cash flows	**4,450,467**	**2,967,671**	**6,506,328**
10% annual discount for estimated timing of cash flows	**(1,993,082)**	**(1,552,173)**	**(2,966,711)**
Standardized measure of discounted future net cash flows	**$ 2,457,385**	**$ 1,415,498**	**$ 3,539,617**

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:

	December 31,		
In thousands	2009	2008	2007
Beginning of year	**$1,415,498**	**$ 3,539,617**	**$1,837,341**
Sales of oil and natural gas produced, net of production costs	**(498,093)**	**(975,708)**	**(672,765)**
Net changes in sales prices	**1,263,346**	**(3,296,580)**	**2,346,008**
Extensions and discoveries, less applicable future development and production costs	**6,735**	**142,199**	**344,615**
Improved recovery[1]	**202,145**	**338,313**	**513,840**
Previously estimated development costs incurred	**98,659**	**157,321**	**192,696**
Revisions of previous estimates, including revised estimates of development costs, reserves and rates of production	**(63,044)**	**(321,733)**	**(214,994)**
Accretion of discount	**192,686**	**538,512**	**269,520**
Acquisition of minerals in place	**365,771**	**12,764**	**32,212**
Sales of minerals in place	**(419,601)**	**(53,356)**	**(121,209)**
Net change in income taxes	**(106,717)**	**1,334,149**	**(987,647)**
End of year	**$2,457,385**	**$ 1,415,498**	**$3,539,617**

(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.

CO_2 Reserves

Based on engineering reports prepared by DeGolyer and MacNaughton, our CO_2 reserves, on a 100% working interest basis, were estimated at approximately 6.3 Tcf at December 31, 2009 (includes 127.1 Bcf of reserves dedicated to three volumetric production payments with Genesis), 5.6 Tcf at December 31, 2008 (includes 153.8 Bcf of reserves dedicated to three volumetric production payments with Genesis), and 5.6 Tcf at December 31, 2007 (includes 182.3 Bcf of reserves dedicated to three volumetric production payments with Genesis). We make reference to the gross amount of proved reserves as that is the amount that is available both for Denbury's tertiary recovery programs and for industrial users who are customers of Denbury and others, as we are responsible for distributing the entire CO_2 production stream for both of these purposes.

NOTE 17. UNAUDITED QUARTERLY INFORMATION

In thousands, except per share amounts	March 31	June 30	September 30	December 31
2009				
Revenues	$ 171,821	$ 215,362	$ 225,415	$ 269,895
Expenses[1]	202,734	358,060	185,987	264,558
Net income (loss)	(18,297)	(87,240)	26,885	3,496
Net income (loss) per share:				
Basic	(0.07)	(0.35)	0.11	0.01
Diluted	(0.07)	(0.35)	0.11	0.01
Cash flow from operations	112,619	148,170	145,645	124,165
Cash flow used for investing activities[2]	(509,539)	(65,301)	(161,550)	(233,324)
Cash flow provided by (used for) financing activities[3]	398,058	(41,117)	(22,365)	108,061
2008				
Revenues	$ 317,255	$ 417,049	$ 407,474	$ 223,924
Expenses[4]	201,446	234,310	156,537	154,535
Net income	73,002	114,053	157,548	43,793
Net income per share:				
Basic	0.30	0.47	0.64	0.18
Diluted	0.29	0.45	0.63	0.18
Cash flow from operations	206,257	164,072	262,442	141,748
Cash flow used for investing activities[5]	(163,688)	(218,384)	(235,605)	(376,982)
Cash flow provided by (used for) financing activities[6]	(28,637)	127,282	1,464	76,993

(1) Includes commodity derivative expense (income) of $20.5 million during the first quarter of 2009, $152.8 million during the second quarter of 2009, $3.7 million during the third quarter of 2009, and $59.2 million during the fourth quarter of 2009. Also includes expenses related to the incentive compensation awards for the management of Genesis in the amount of $14.2 million in 2009 (see Note 3, "Related Party Transactions – Genesis."). In June 2009, we expensed a $10.0 million ($3.65 million in cash and $6.35 million of the Company's 9.75% Senior Subordinated Notes due 2016) compensation charge associated with retirement of Gareth Roberts as CEO and President of the Company. During the fourth quarter of 2009, we incurred $8.7 million in expenses related to the Encore acquisition (see Note 2, "Acquisitions and Divestitures.")

(2) During the first quarter of 2009, we made cash payments of approximately $197.9 million associated with the Hasting Field Acquisition. During June and July of 2009, we received cash payments of approximately $197.5 million and $62.3 million, respectively, for the sale of 60% of our Barnett Shale natural gas assets. During the fourth quarter of 2009, we received cash payments of approximately $210.0 million for the sale of our remaining 40% interests in our Barnett Shale natural gas assets. During the fourth quarter of 2009, we acquired Conroe Field for a cash payment of approximately $254.2 million and 11,620,000 shares of Denbury common stock (see Note 2, "Acquisitions and Divestitures.")

(3) In the first quarter of 2009, we issued $420 million of 9.75% Senior Subordinated Notes due 2016, and received net proceeds of $381.4 million (see Note 6, "Long-term Debt.")

(4) Includes commodity derivative expense (income) of $46.8 million in the first quarter of 2008, $58.8 million in the second quarter of 2008, ($62.0) million in the third quarter of 2008, and ($243.6) million in the fourth quarter of 2008. We had a full cost ceiling write-down of $226 million during the fourth quarter of 2008. In addition, during the third quarter of 2008, we expensed approximately $30 million associated with a non-refundable deposit on a cancelled acquisition.

(5) In December 2007 and February 2008, we received cash proceeds of $108.6 million and $48.9 million, respectively, for the sale of our Louisiana natural gas assets (see Note 2, "Acquisitions and Divestitures.")

(6) In the second quarter of 2008, we received $225 million in cash from two financing leases entered into with Genesis (see Note 3, "Related Party Transactions — Genesis"). Also during 2008, we had net borrowings of $75 million during the fourth quarter, and net payments of $39 million during the first quarter, and $111 million in the second quarter, all under our senior bank loan.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) was performed under the supervision and with the participation of the Company's management, including our Chief Executive Officer and our Chief Financial Officer. Based on that evaluation, the Company's Chief Executive Officer and our Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2009 to ensure: that information required to be disclosed in the reports it files and submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms; and that information that is required to be disclosed under the Exchange Act is accumulated and communicated to the Company's management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Evaluation of Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we have determined that, during the fourth quarter of fiscal 2009, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

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

The effectiveness of the Company's internal control over financial reporting as of December 31, 2009, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Important Considerations

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

ITEM 9B. OTHER INFORMATION

None.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Except as disclosed below, information as to Item 10 will be set forth in the Proxy Statement ("Proxy Statement") for the Annual Meeting of Shareholders to be held May 19, 2010, ("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 70. All financial statement schedules have been omitted because they are not applicable or the required information is presented in the financial statements or the notes to consolidated financial statements.

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

Exhibit No.	Exhibit
2	Agreement and Plan of Merger by and between Encore Acquisition Company and Denbury Resources Inc. Executed on October 31, 2009 (incorporated by reference as Exhibit 2.1 of our Form 8-K filed November 5, 2009).
3(a)	Restated Certificate of Incorporation of Denbury Resources Inc. filed with the Delaware Secretary of State on December 29, 2003 (incorporated by reference as Exhibit 3.1 of our Form 8-K filed December 29, 2003).
3(b)	Certificate of Amendment of Restated Certificate of Incorporation of Denbury Resources Inc. filed with the Delaware Secretary of State on October 20, 2006 (incorporated by reference as Exhibit 3(a) of our Form 10-Q filed November 8, 2005).
3(c)	Certificate of Amendment of Restated Certificate of Incorporation of Denbury Resources Inc. filed with the Delaware Secretary of State on November 21, 2007 (incorporated by reference as Exhibit 3(c) of our Form 10-K filed February 29, 2008).
3(d)	Bylaws of Denbury Resources Inc., a Delaware corporation, adopted December 29, 2003 (incorporated by reference as Exhibit 3.2 of our Form 8-K filed December 29, 2003).
4(a)	Indenture for $225 million of 7.5% Senior Subordinated Notes due 2013 among Denbury Resources Inc., certain of its subsidiaries and JP Morgan Chase Bank as trustee, dated March 25, 2003 (incorporated by reference as Exhibit 4(a) of our Registration Statement No. 333-105233-04 on Form S-4, filed May 14, 2003).
4(b)	First Supplemental Indenture to Indenture for $225 million of 7.5% Senior Subordinated Notes due 2013 dated as of December 29, 2003, among Denbury Resources Inc., certain of its subsidiaries, and the JP Morgan Chase Bank, as trustee (incorporated by reference as Exhibit 4.1 of our Form 8-K filed December 29, 2003).
4(c)*	Second Supplemental Indenture to Indenture for $225 million of 7.5% Senior Subordinated Notes due 2013 dated as of July 24, 2009, among Denbury Resources Inc., certain of its subsidiaries, and JP Morgan Chase Bank, as trustee.
4(d)	Indenture for $150 million of 7.5% Senior Subordinated Notes due 2015 among Denbury Resources Inc., certain of its subsidiaries, and JP Morgan Chase Bank, as trustee (incorporated by reference as Exhibit 4.1 of our Form 8-K filed December 9, 2005).
4(e)	First Supplemental Indenture for $150 million of 7.5% Senior Subordinated Notes due 2015, dated April 3, 2008, between Denbury Resources Inc., as issuer, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference as Exhibit 4.1 of our Form 8-K filed April 3, 2007).
4(f)*	Second Supplemental Indenture to Indenture for $150 million of 7.5% Senior Subordinated Notes due 2015, dated July 24, 2009, between Denbury Resources Inc., as issuer, and The Bank of New York Trust Company, N.A., as Trustee.
4(g)	Indenture for $420 million of 9.75% Senior Subordinated Notes due 2016 among Denbury Resources Inc., certain of its subsidiaries, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference as Exhibit 4.1 of our Form 8-K filed February 17, 2009).
4(h)*	First Supplemental Indenture to Indenture for $420 million of 9.75% Senior Subordinated Notes due 2016, dated June 30, 2009, between Denbury Resources Inc., as issuer, and The Bank of New York Mellon Trust Company, N.A., as Trustee.
4(i)	Indenture for $1 billion of 8¼% Senior Subordinated Notes due 2020 among Denbury Resources Inc., certain of its subsidiaries, and Wells Fargo, National Association, as Trustee (incorporated by reference as Exhibit 4.1 of our Form 8-K filed February 12, 2010).

Exhibit No.	Exhibit
4(j)	Registration Rights Agreement dated as of December 18, 2009 (incorporated by reference as Exhibit 4.1 of our Form 8-K filed December 23, 2009).
10(a)	Sixth Amended and Restated Credit Agreement among Denbury Onshore, LLC, as Borrower, Denbury Resources Inc., as Parent Guarantor and JPMorgan Chase Bank, N.A., as Administrative Agent, and certain other financial institutions, dated September 14, 2007 (incorporated by reference as Exhibit 10.1 of our Form 8-K filed September 19, 2006).
10(b)	First Amendment to Sixth Amended and Restated Credit Agreement among Denbury Onshore, LLC, as Borrower, Denbury Resources Inc., as Parent Guarantor, JPMorgan Chase Bank, N.A., as Administrative Agent and certain other financial institutions effective March 31, 2008 (incorporated by reference as Exhibit 10 of our Form 10-Q for the quarter ended March 31, 2007).
10(c)	Second Amendment to Sixth Amended and Restated Credit Agreement among Denbury Onshore, LLC, as Borrower, Denbury Resources Inc., as Parent Guarantor, JPMorgan Chase Bank, N.A., as Administrative Agent, and certain other financial institutions dated as of October 7, 2008 (incorporated by reference as Exhibit 10(a) of our Form 10-Q for the quarter ended September 30, 2008).
10(d)	Third Amendment to Sixth Amended and Restated Credit Agreement among Denbury Onshore, LLC, as Borrower, Denbury Resources Inc., as Parent Guarantor, JPMorgan Chase Bank, N.A., as Administrative Agent, and certain other financial institutions dated as of February 6, 2009 (incorporated by reference as Exhibit 10(d) of our Form 10-K for the year ended December 31, 2008).
10(e)	Amendment for Increased Borrowing Base from $500 million to $1.0 billion to Sixth Amended and Restated Credit Agreement among Denbury Onshore, LLC, as Borrower, and JPMorgan Chase Bank, N.A., as Administrative Agent, and certain other financial institutions dated as of March 28, 2008 (incorporated by reference as Exhibit 10(a) of our Form 10-Q for the quarter ended March 31, 2008).
10(f)	Fourth Amendment to Sixth Amended and Restated Credit Agreement among Denbury Onshore, LLC, as Borrower, Denbury Resources Inc., as Parent Guarantor, JPMorgan Chase Bank, N.A., as Administrative Agent, and certain other financial institutions, dated as of December 16, 2009 (incorporated by reference as Exhibit 99.1 of our Form 8-K filed December 23, 2009).
10(g)*	Fifth Amendment to Sixth Amended and Restated Credit Agreement among Denbury Onshore, LLC, as Borrower, Denbury Resources Inc., as Parent Guarantor, JPMorgan Chase Bank, N.A., as Administrative Agent, and certain other financial institutions, dated as of January 22, 2010.
10(h)*	Sixth Amendment to Sixth Amended and Restated Credit Agreement among Denbury Onshore, LLC, as Borrower, Denbury Resources Inc., as Parent Guarantor, and JPMorgan Chase Bank, N.A., as Administrative Agent, and certain other financial institutions, dated as of January 29, 2010.
10(i)	Pipeline Financing Lease Agreement by and between Genesis NEJD Pipeline, LLC as Lessor, and Denbury Onshore, LLC, as Lessee, dated May 30, 2008 (incorporated by reference as Exhibit 99.1 of our Form 8-K filed on June 5, 2008).
10(j)	Transportation Services Agreement by and between Genesis Free State Pipeline, LLC and Denbury Onshore, LLC, dated May 30, 2008 (incorporated by reference as Exhibit 99.2 of our Form 8-K filed on June 5, 2008).
10(k)**	Denbury Resources Inc. Amended and Restated Stock Option Plan as of December 5, 2007 (incorporated by reference as Exhibit 99.2 of our Form 8-K, filed December 11, 2007).
10(l)**	Denbury Resources Inc. Stock Purchase Plan, as amended and restated December 5, 2007 (incorporated by reference as Exhibit 99.4 of our Form 8-K, filed December 11, 2007).
10(m)**	Form of indemnification agreement between Denbury Resources Inc. and its officers and directors (incorporated by reference as Exhibit 10 of our Form 10-Q for the quarter ended June 30, 1999).
10(n)**	Denbury Resources Inc. Directors Compensation Plan (incorporated by reference as Exhibit 4 of our Registration Statement on Form S-8, No. 333-39172, filed June 13, 2000, amended March 2, 2001 and May 11, 2006).

Exhibit No.	Exhibit
10(o)**	Denbury Resources Severance Protection Plan, as amended and restated effective December 30, 2008 (incorporated by reference as Exhibit 10(n) of our Form 10-K for the year ended December 31, 2008).
10(p)**	Denbury Resources Inc. 2004 Omnibus Stock and Incentive Plan, as amended and restated effective December 30, 2008 (incorporated by reference as Exhibit 10(o) of our Form 10-K for the year ended December 31, 2008).
10(q)**	2006 Form of stock appreciation rights agreement that vests 100% four years from the date of grant, for grants to employees and officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(w) of our Form 10-K for the year ended December 31, 2006).
10(r)**	2006 Form of stock appreciation rights agreement that cliff vests 100% four years from the date of grant, for grants to directors pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(x) of our Form 10-K for the year ended December 31, 2006).
10(s)**	2006 Form of restricted stock award that vests 25% per annum, for grants to new employees and officers on their hire date pursuant to 2004 Omnibus and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(y) of our Form 10-K for the year ended December 31, 2006).
10(t)**	2006 Form of restricted stock award that cliff vests 100% four years from the date of grant for grants to employees and officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(z) of our Form 10-K for the year ended December 31, 2006).
10(u)**	2007 Form of restricted stock award to officers that cliff vests on March 31, 2010 pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(y) of our Form 10-K for the year ended December 31, 2008).
10(v)**	2007 Form of performance share awards to officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(z) of our Form 10-K for the year Ended December 31, 2007).
10(w)**	2007 Form of restricted stock award to directors that cliff vests after three years pursuant to 2004 Omnibus Stock and Incentive Plan (incorporated by reference as Exhibit 10(cc) of our Form 10-K for the year ended December 31, 2007).
10(x)**	2007 Form of restricted stock award to new directors that vest 20% per annum (incorporated by reference as Exhibit 10(z) of our Form 10-K for the year ended December 31, 2007).
10(y)**	Form of deferred payment cash award that cliff vests 100% four years from the date of grant for grants to employees and officers (incorporated by reference as exhibit 10(bb) of our Form 10-K for the year ended December 31, 2005).
10(z)**	2008 Form of restricted stock award to certain officers that cliff vests on March 31, 2011 (incorporated by reference as Exhibit 10(b) of our Form 10-Q for the first quarter ended March 31, 2008).
10(aa)**	2008 Form of restricted stock award without change of control vesting to certain officers that cliff vests on March 31, 2011 (incorporated by reference as Exhibit 10(c) of our Form 10-Q for the first quarter ended March 31, 2008).
10(bb)**	2008 Form of performance share awards to certain officers with change of control vesting (incorporated by reference as Exhibit 10(d) of our Form 10-Q for the first quarter ended March 31, 2008).
10(cc)**	2008 Form of performance share awards to certain officers without change of control vesting (incorporated by reference as Exhibit 10(e) of our Form 10-Q for the first quarter ended March 31, 2008).
10(dd)**	2004 Form of restricted stock award that vests 20% per annum, for grants to officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(k) of our Form 10-K for the year ended December 31, 2004).

Exhibit No.	Exhibit
10(ee)**	2004 Form of restricted stock award that vests on retirement, for grants to officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(l) of our Form 10-K for the year ended December 31, 2004).
10(ff)**	2004 Form of restricted stock award that vests 20% per annum, for grants to directors pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(m) of our Form 10-K for the year ended December 31, 2004).
10(gg)**	2009 form of restricted stock award to certain officers that cliff vests on March 31, 2012 pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(b) of our Form 10-Q for the quarter ended March 31, 2009).
10(hh)**	2009 form of restricted stock award without change of control vesting to certain officers that cliff vests on March 31, 2012 pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(c) of our Form 10-Q for the quarter ended March 31, 2009).
10(ii)**	2009 form of performance share awards to certain officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(d) of our Form 10-Q for the quarter ended March 31, 2009).
10(jj)**	2009 form of performance share awards without change of control vesting to certain officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(e) of our Form 10-Q for the quarter ended March 31, 2009).
10(kk)**	2009 form stock appreciation rights to certain officers that cliff vests on March 31, 2012 pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(f) of our Form 10-Q for the quarter ended March 31, 2009).
10(ll)**	2009 form of stock appreciation rights without change of control vesting pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(g) of our Form 10-Q for the quarter ended March 31, 2009).
10(mm)**	Founder's Retirement Agreement by and between Denbury Resources Inc. and Gareth Roberts effective June 30, 2009 (incorporated by reference as Exhibit 10.1 of our Form 8-K filed July 7, 2009).
10(nn)**	$6.350 million 9.75% Senior Subordinated Note due 2016 issued on June 30, 2009 to Gareth Roberts (incorporated by reference as Exhibit 10.2 of our Form 8-K filed July 7, 2009).
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, 2009, on oil and gas reserves (SEC Case) dated January 26, 2010.
101*	The following financial statements from the Company's Annual Report on Form 10-K for the year ended December 31, 2009, formatted in XBRL: (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statements of Cash Flows, (iv) Consolidated Statements of Changes in Stockholders' Equity, (v) Consolidated Statements of Comprehensive Operations.

* 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., 5100 Tennyson Pkwy., Suite 1200, Plano, TX 75024.

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 26, 2010

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

/s/ Alan Rhoades February 26, 2010

Alan Rhoades
Vice President, Accounting

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 26, 2010

Phil Rykhoek
Chief Executive Officer
(Principal Executive Officer)

/s/ Mark C. Allen February 26, 2010

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

/s/ Alan Rhoades February 26, 2010

Alan Rhoades
Vice President, Accounting
(Principal Accounting Officer)

/s/ Gareth Roberts February 26, 2010

Gareth Roberts
Director

Wieland Wettstein
Director

/s/ Michael Beatty February 26, 2010

Michael Beatty
Director

/s/ Michael Decker February 26, 2010

Michael Decker
Director

/s/ Ron Greene February 26, 2010

Ron Greene
Director

/s/ David I. Heather February 26, 2010

David I. Heather
Director

/s/ Greg McMichael February 26, 2010

Greg McMichael
Director

/s/ Randy Stein February 26, 2010

Randy Stein
Director

EXHIBIT 21

LIST OF SUBSIDIARIES

Name of Subsidiary	Jurisdiction of Organization
Denbury Gathering & Marketing, Inc.	Delaware
Denbury Operating Company	Delaware
Denbury Onshore, L.L.C.	Delaware
Denbury Marine, L.L.C.	Louisiana
Tuscaloosa Royalty Fund L.L.C.	Delaware
Denbury New Frontiers, L.L.C.	Delaware
Denbury Green Pipeline – Texas, LLC	Delaware

EXHIBIT 23 (A)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (Nos. 333-1006, 333-27995, 333-55999, 333-70485, 333-39172, 333-39218, 333-63198, 333-90398, 333-106253, 333-116249, 333-143848 and 333-160178), Form S-3 (No. 333-164653), and Form S-4 (No. 333-163521) of Denbury Resources Inc. of our report dated March 1, 2010 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

Dallas, Texas
March 1, 2010

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 March 1, 2010

Phil Rykhoek
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 March 1, 2010

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

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, 2009 (the Report) of Denbury Resources Inc. (Denbury) as filed with the Securities and Exchange Commission on March 1, 2010, 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 March 1, 2010

Phil Rykhoek
Chief Executive Officer

/s/ Mark C. Allen March 1, 2010

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

Corporate Information

Stock Exchange Listing
NYSE: DNR

Corporate Headquarters
Denbury Resources Inc.
5100 Tennyson Pkwy, Ste. 1200
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
59 Maiden Lane
Plaza Level
New York, NY 10038
(800) 937-5449
Email: info@amstock.com
www.amstock.com

Investor Inquiries
Phil Rykhoek
Chief Executive Officer
(972) 673-2050

Mark Allen
Senior Vice President & Chief Financial Officer
(972) 673-2007

Laurie Burkes
Investor Relations Manager
(972) 673-2166
Email: ir@denbury.com

Annual Certifications
In 2009, the Company submitted its written affirmation and annual Chief Executive Officer certification pursuant to Section 303A of the New York Stock Exchange regulations without qualifications.

Financial Information Requests
To receive additional copies of the Annual Report on Form 10-K as filed with the SEC or to obtain other Denbury public documents, please contact:

Denbury Resources Inc.
Investor Relations
5100 Tennyson Pkwy, Ste. 1200
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.

Note that these documents are also available on our website at www.denbury.com.

Annual Meeting
The Annual Meeting of Shareholders will be held on Wednesday, May 19, 2010, at 3:00 P.M. CDT at the Embassy Suites Dallas – Frisco/Hotel Convention Center, located at 7600 John Q. Hammons Drive, Frisco, Texas 75034. A proxy statement and notice of the Annual Meeting have been sent to shareholders of record as of March 31, 2010.

Legal Counsel
Baker & Hostetler LLP

Bankers
JP Morgan (Agent)

Auditors
PricewaterhouseCoopers LLP

Reserve Engineers
DeGolyer & MacNaughton

Designed by Eisenberg And Associates Printing by ColorDynamics

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Trees	Energy	Kilo-Watt Hours	Greenhouse Gases	Water	Solid Waste
44 fully grown	30.5 million BTU	5504.79 kwh	15,019.3 pounds	16,025 gallons	2,651 pounds