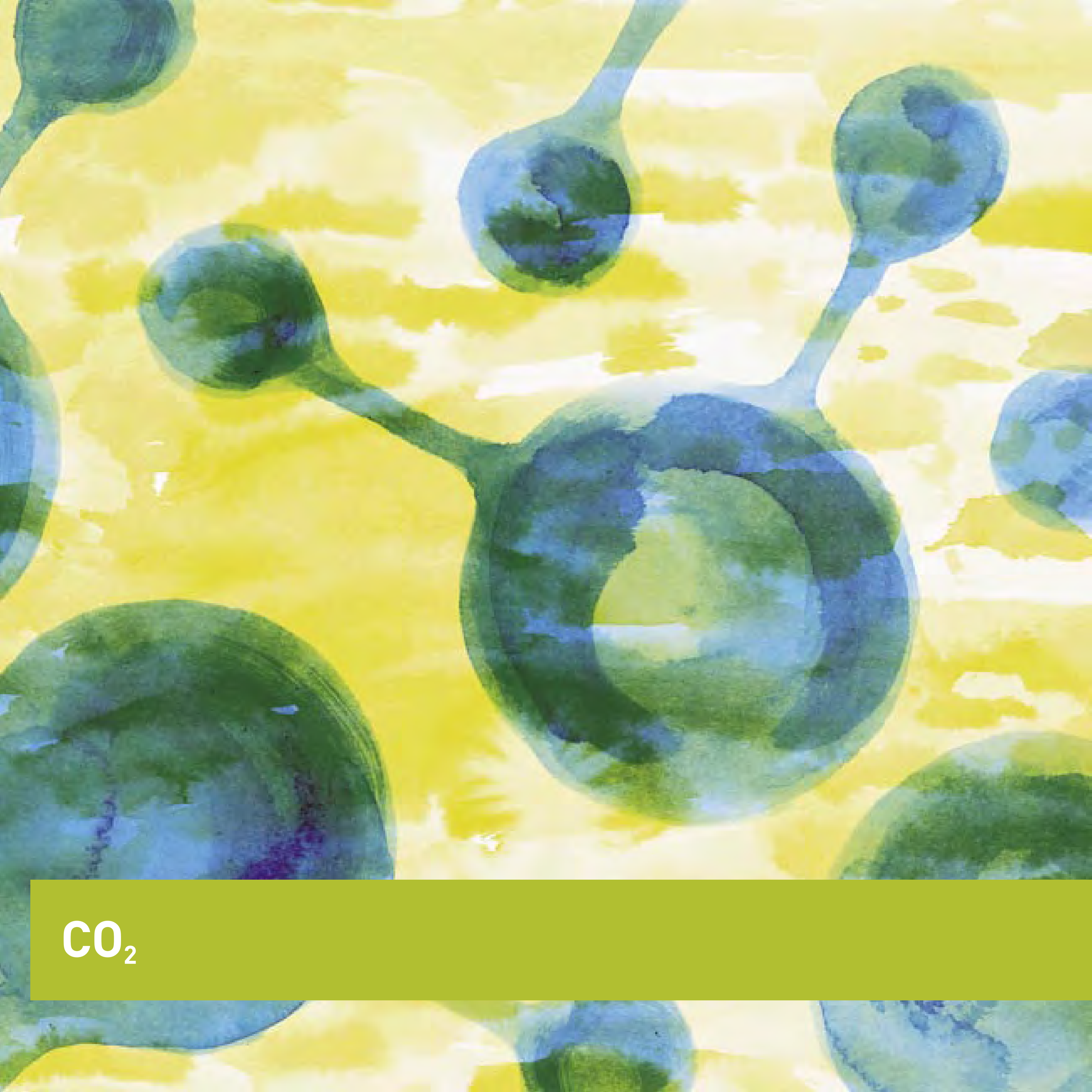
# The Future in $CO_2$

Denbury Resources Inc. 2006 Annual Report



# $CO_2$

Because of Denbury's unique ability to sequester Carbon Dioxide ($CO_2$) while increasing oil production from previously depleted oil fields, we not only improve the local economies in which we operate, but can also help reduce our nation's need for imported oil.

| Amounts in thousands, unless otherwise noted | Year Ended December 31, 2006 | 2005 | 2004[2] | 2003 | 2002 | Average Annual Growth[1] |
|---|---|---|---|---|---|---|
| **Consolidated Statements of Operations Data:** | | | | | | |
| Revenues | **$ 731,536** | $ 560,392 | $ 382,972 | $ 333,014 | $ 285,152 | 27% |
| Net income | **202,457[3]** | 166,471 | 82,448 | 56,553[4] | 46,795 | 44% |
| Net income per common share[5]: | | | | | | |
| Basic | **$ 1.74[3]** | $ 1.49 | $ 0.75 | $ 0.52[4] | $ 0.44 | 41% |
| Diluted | **1.64[3]** | 1.39 | 0.72 | 0.51[4] | 0.43 | 40% |
| Weighted average number of common shares outstanding[5]: | | | | | | |
| Basic | **116,550** | 111,743 | 109,741 | 107,763 | 106,487 | 2% |
| Diluted | **123,774** | 119,634 | 114,603 | 110,928 | 108,730 | 3% |
| **Consolidated Statements of Cash Flow Data:** | | | | | | |
| Cash provided by (used by): | | | | | | |
| Operating activities | **$ 461,810** | $ 360,960 | $ 168,652 | $ 197,615 | $ 159,600 | 30% |
| Investing activities | **(856,627)** | (383,687) | (93,550) | (135,878) | (171,161) | 50% |
| Financing activities | **283,601** | 154,777 | (66,251) | (61,489) | 12,005 | 120% |
| **Production (Daily):** | | | | | | |
| Oil (Bbls) | **22,936** | 20,013 | 19,247 | 18,894 | 18,833 | 5% |
| Natural gas (Mcf) | **83,075** | 58,696 | 82,224 | 94,858 | 100,443 | (5%) |
| BOE (6:1) | **36,782** | 29,795 | 32,951 | 34,704 | 35,573 | 1% |
| **Unit Sales Price (excluding hedges):** | | | | | | |
| Oil (per Bbl) | **$ 59.87** | $ 50.30 | $ 36.46 | $ 27.47 | $ 22.36 | 28% |
| Natural gas (per Mcf) | **7.10** | 8.48 | 6.24 | 5.66 | 3.31 | 21% |
| **Unit Sales Price (including hedges):** | | | | | | |
| Oil (per Bbl) | **$ 59.23** | $ 50.30 | $ 27.36 | $ 24.52 | $ 22.27 | 28% |
| Natural gas (per Mcf) | **7.10** | 7.70 | 5.57 | 4.45 | 3.35 | 21% |
| **Costs per BOE:** | | | | | | |
| Lease operating expenses | **$ 12.46** | $ 9.98 | $ 7.22 | $ 7.06 | $ 5.48 | 23% |
| Production taxes and marketing expenses | **2.71** | 2.54 | 1.55 | 1.17 | 0.92 | 31% |
| General and administrative | **3.20** | 2.62 | 1.78 | 1.20 | 0.96 | 35% |
| Depletion, depreciation, and amortization | **11.11** | 9.09 | 8.09 | 7.48 | 7.26 | 11% |
| **Proved Reserves:** | | | | | | |
| Oil (MBbls) | **126,185** | 106,173 | 101,287 | 91,266 | 97,203 | 7% |
| Natural gas (MMcf) | **288,826** | 278,367 | 168,484 | 221,887 | 200,947 | 9% |
| MBOE (6:1) | **174,322** | 152,568 | 129,369 | 128,247 | 130,694 | 7% |
| Carbon dioxide (MMcf)[6] | **5,525,948** | 4,645,702 | 2,664,633 | 1,613,840 | 815,315 | 61% |
| **Consolidated Balance Sheet Data:** | | | | | | |
| Total assets | **$ 2,139,837** | $ 1,505,069 | $ 992,706 | $ 982,621 | $ 895,292 | 24% |
| Total long-term liabilities | **833,380** | 617,343 | 368,128 | 434,845 | 432,616 | 18% |
| Stockholders' equity[7] | **1,106,059** | 733,662 | 541,672 | 421,202 | 366,797 | 32% |

(1) Four-year compounded average annual growth rate computed using 2002 as a base year.

(2) We sold Denbury Offshore, Inc. in July 2004.

(3) Effective January 1, 2006, we adopted Statement of Financial Accounting Standards No. 123(R), "Share Based Payment."

(4) In 2003, we recognized a gain of $2.6 million for the cumulative effect of the adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations." The adoption of SFAS 143 increased basic and diluted net income per common share by $0.02. In April 2003, we recorded a pre-tax charge of $17.6 million associated with early debt retirement.

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

(6) Based on a gross working interest basis and includes reserves dedicated to volumetric production payments of 210.5 Bcf at December 31, 2006, 237.1 Bcf at December 31, 2005, 178.7 Bcf at December 31, 2004 and 162.6 Bcf at December 31, 2003. (See Note 14 to the Consolidated Financial Statements.)

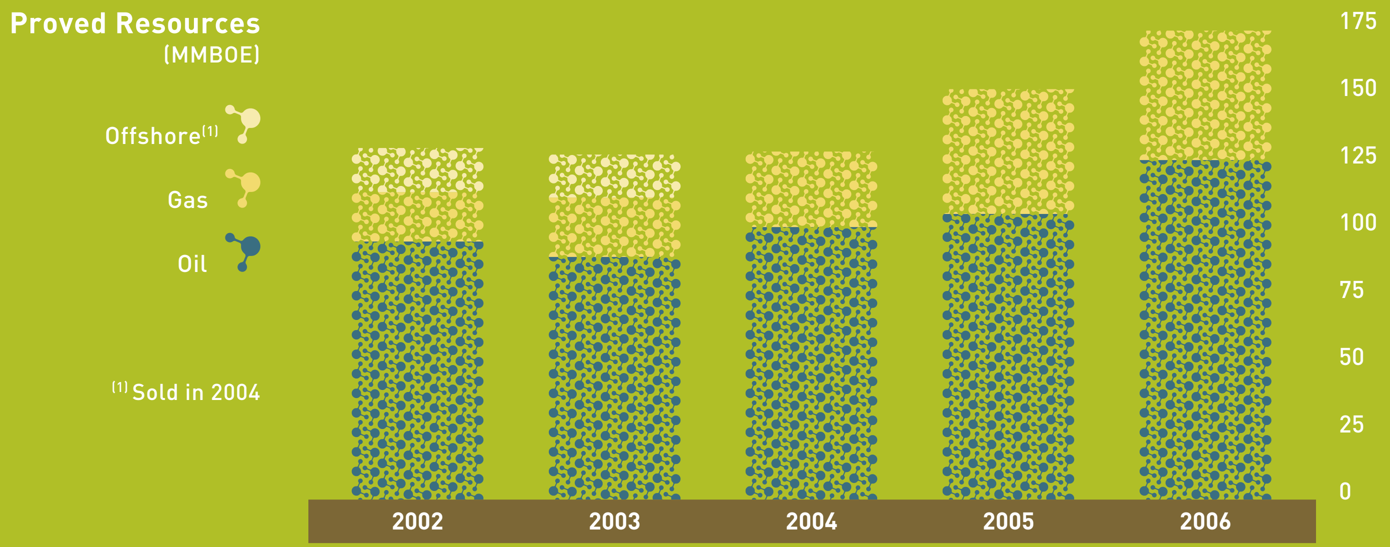
(7) We have never paid any dividends on our common stock.

**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 page 28 regarding cautionary notes about forward-looking statements and unproved reserves referenced herein.**

**To Our Shareholders:**

2006 was another good year for Denbury Resources despite rising costs and equipment delays that have been affecting our entire industry. While we had record annual net income and cash flow from operations, largely attributable to higher production and commodity prices, the year was noteworthy as one during which we significantly expanded our strategy that has taken several years to develop. In short, what began several years ago as a small but effective strategy to extract more oil from mature fields in Mississippi using an unusual large naturally-occurring deposit of carbon dioxide located near Jackson Dome, has developed into a broader, more attractive strategy to extract hundreds of millions of barrels of oil from fields throughout much of the Gulf Coast region. We have already identified around 300 MMBbls of potential oil reserves that may be recoverable from fields that we currently own or have a contract to buy, over and above the 62.2 MMBbls of proven tertiary oil reserves already on our books at December 31, 2006, and we are actively attempting to add to this inventory of oil fields. The proved oil reserves in our $CO_2$ fields have a PV-10 Value of $1.46 billion, using December 31, 2006 constant NYMEX pricing of $61.05 per Bbl, and we have estimated a PV-10 Value of our probable $CO_2$ related oil reserves of $3.3 billion using the same prices (on an unrisked basis, including the mid-point of the reserve range at Hastings Field, but excluding our pending acquisition). Although it will take several years to realize the ultimate fruits of our expanded strategy, the first steps were taken in 2006. Highlights of these steps are as follows:

1. Our proved natural $CO_2$ reserves at Jackson Dome increased 19% during 2006, to 5.5 Tcf, enough to flood our announced Phases I through V principally in our Mississippi area, develop Citronelle Field (Southwest Alabama), develop Hastings Field (our first South Texas Field which we have an option to acquire), take care of our industrial customers, and still leave us with approximately 250 Bcf to use in expansion elsewhere. While we are happy with our expansion results to date, we aren't finished yet, as we believe that there are more potential $CO_2$ reserves at Jackson Dome, perhaps an additional two to three Tcf.




2. We are also pursuing man-made (anthropogenic) sources of $CO_2$ to supplement our natural $CO_2$ reserves. We are particularly interested in certain proposed new industrial chemical plants that will convert petroleum coke or coal into a variety of products, including ammonia, methanol, synthetic diesel fuel or electrical power. These type plants produce $CO_2$ in a form and at a price that is attractive to us. In 2006, we entered into our first agreement with this type of plant wherein we committed to purchase 100% of the $CO_2$ production (assuming the plant is built) from the proposed Faustina ammonia plant to be built near Donaldsonville, Louisiana. If this plant is built, it is expected to produce approximately 200 MMcf/d when completed in 2010 and provide us with the potential equivalent volume of an additional one Tcf of $CO_2$ over the 15 year term of our contract. We are in discussions with several other entities that are considering the construction of these types of plants, which if consummated, could significantly increase our sources of $CO_2$.

3. We announced the planned expansion of our tertiary operations to the South Texas Gulf Coast area, outside of our prior core area. In late 2006, we acquired an option to purchase Hastings Field, a strategically significant potential $CO_2$ tertiary candidate south of Houston, Texas. This will require the construction of the Green Line as discussed below, but with the excess $CO_2$ reserves at Jackson Dome and the addition of man-made $CO_2$ from the proposed Faustina plant, this option gives us an anchor field to enable our expansion into a new and attractive area. We plan to acquire several more fields in this area, and in February 2007 announced an agreement to purchase two tertiary flood candidates also in the Houston area, Oyster Bayou and Fig Ridge Fields. In just a few short months, with these two acquisitions, we have added 80 to 130 MMBbls of additional potential oil reserves recoverable through tertiary oil operations.

4. We continue to expand our network of $CO_2$ pipeline systems. Early in 2006, we finished the 86-mile, 20 inch Free State $CO_2$ line from Jackson Dome to eastern Mississippi (our Phase II) and began injecting $CO_2$ into three fields in that area (Eucutta, Soso and Martinville). We also acquired an idle natural gas line in West Mississippi, which we are in the process of converting to $CO_2$ service (for our Phase IV), and we acquired an 8 inch natural gas pipeline that runs from Jackson Dome to Tinsley Field (our Phase III). We have converted this Tinsley line to $CO_2$ service and we are currently using it to transport limited volumes of $CO_2$ from Jackson Dome to Tinsley Field. We plan to start a new $CO_2$ pipeline, named our Delta system, in 2007. It will consist of a 31-mile 24 inch segment running from Jackson Dome to Tinsley Field (to replace our smaller eight inch line), and a 68-mile 20 inch extension of that line on to Delhi Field (our Phase V). Currently, we anticipate that the Tinsley portion should be completed in late 2007 and the Delhi portion should be completed by mid-2008.

More significantly, we announced our intention to expand our $CO_2$ pipeline network to the Texas Gulf Coast region. We plan to build a 280 to 300 mile $CO_2$ pipeline (named our Green line) from near the end of our existing NEJD line in Louisiana to Hastings Field, near Houston, Texas. Currently, we expect to have this

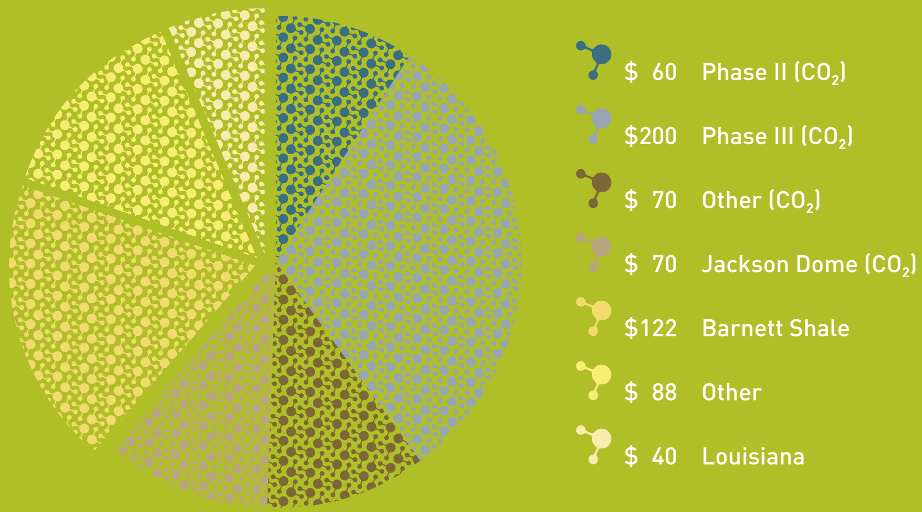
**We plan to build a 280 to 300 mile $CO_2$ pipeline (named our Green Line) from near the end of our existing NEJD line in Louisiana to Hastings Field, near Houston, Texas.**

**Projected 2007 Capital Budget**

In Millions

$650[1]

[1] Excludes acquisitions and capitalized interest




expansion completed during 2009, which will allow us to start injection at Hastings Field shortly thereafter.

It is now clear that we can use our large natural reserves of $CO_2$ at Jackson Dome and our knowledge of $CO_2$ flooding in mature oil reservoirs to expand beyond our original core area. Several proposed new industrial sources of $CO_2$ will produce $CO_2$ in large enough quantities for our use, and given environmental concerns about releasing $CO_2$ into the atmosphere, we believe that we can negotiate attractive terms for the purchase of this $CO_2$. It is not clear how many of these plants will be built, but they seem to be a reasonable solution, given higher energy costs, to the burning of traditional fossil fuels. These plants use carbon in the form of petroleum coke or coal to produce syngas ($CO + H_2$), which can be used for the production of ammonia, methanol, synthetic diesel or electrical power generation. Because the carbon is burnt in pure oxygen gas, pure $CO_2$ is a natural byproduct, one that we can sequester as part of our tertiary $CO_2$ flooding process. We can use the anthropogenic $CO_2$ in exactly the same way as our natural $CO_2$

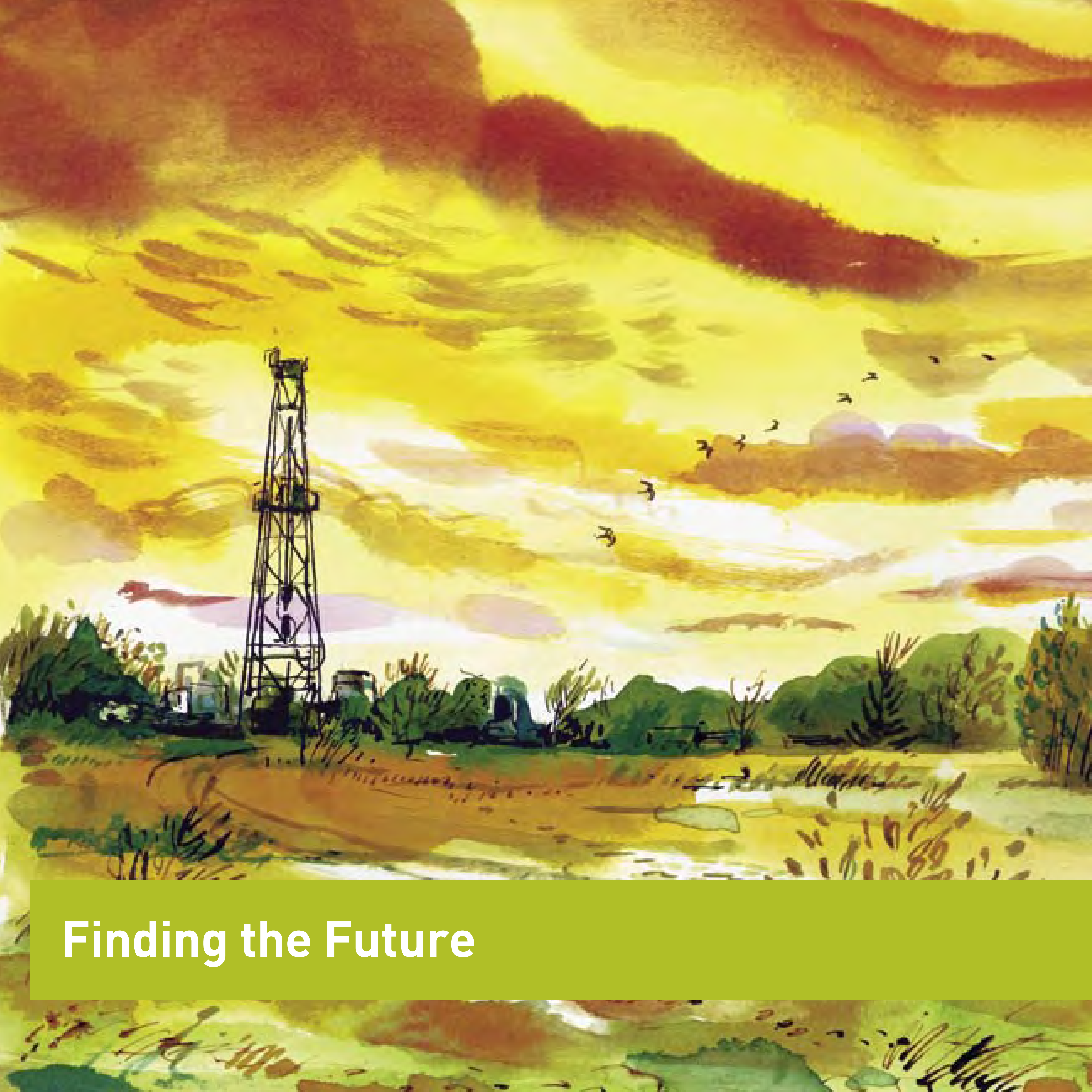
from Jackson Dome, which means that the $CO_2$ will be cycled through the oil reservoirs to recover incremental oil, but will ultimately be left in the oil field when the process is completed. Furthermore, the $CO_2$ will be held in natural geological structures that have trapped oil and natural gas for millions of years, with virtually no chance of remigration in the next several thousand years. With the continued expansion of our $CO_2$ pipeline system, the only one in this region, our large and growing inventory of oil fields that are tertiary flood candidates, backstopped with our naturally occurring source of $CO_2$ at Jackson Dome, we may be the best positioned customer to provide these potential plant owners a way to dispose of their $CO_2$ in an environmentally friendly way. We are in an enviable position to acquire these new sources of $CO_2$ and to acquire and flood the mature oil fields in our expanded areas of operations.

> **We may be the best positioned customer to provide these potential plant owners a way to dispose of their $CO_2$ in an environmentally friendly way.**

One further point is that we have built a strong, experienced team of dedicated and incentivized employees, numbering 615 at last count, who are working on projects from Texas to Florida. This team has developed the skills and expertise needed to pursue our strategy and the results that we achieve are directly attributable to their efforts.

Because of our unique ability to sequester $CO_2$ while increasing oil production from previously depleted oil fields, we not only improve the local economies in which we operate, but can also help reduce our nation's need for imported oil. While we may not be able to save the planet by simultaneously reducing global warming and postponing the peak global oil production, it is clear that looking at the world through $CO_2$ has given us a whole new perspective. Hence the theme for this year's annual report.

Gareth Roberts
President and Chief Executive Officer
March 9, 2007



# Finding the Future

## $CO_2$ Tertiary Operations

Our tertiary operations are our core assets and our principal focus. During the last seven years, we have learned a considerable amount about tertiary operations and working with carbon dioxide ("$CO_2$") and our knowledge continues to grow. We like these tertiary operations because (i) tertiary investments provide a reasonable rate of return, even at relatively low oil prices of around $30 per barrel, (ii) tertiary flooding exhibits a lower risk profile than conventional exploration and development, and (iii) to date, in our region of the United States, we have not encountered any industry competition. Generally, from the Texas Gulf Coast to Florida, there are no known significant natural sources of carbon dioxide except our own, and these large volumes of $CO_2$ are the foundation for our entire tertiary program.

As of year end 2006, we had a total of 62.2 MMBbls of proved reserves attributable to our tertiary operations, 51.7 MMBbls of which were attributable to fields in Phase I with the balance in one field in Phase II. To date, we have already produced over 15 MMBbls from tertiary operations and we have identified up to 215 MMBbls of additional potential or probable reserves that can be recovered through tertiary operations in our five currently planned phases, plus Citronelle Field. We also believe we have from 50 to 90 MMBbls of potential reserves recoverable through tertiary operations at Hastings Field and 30 to 40 MMBbls at our most recent acquisition (expected to close in March 2007), Oyster Bayou and Fig Ridge Fields, or a total future potential of 295 MMBbls to 345 MMBbls, over and above our 62.2 MMBls of existing proven reserves.

Through December 31, 2006, we have spent a total of $665.4 million on fields currently being flooded with $CO_2$ (including allocated acquisition costs) and have received $472.2 million in net cash flow (revenue less operating expenses and capital expenditures). Of this total, approximately $273.5 million was spent on fields that had little or no proved reserves

Continued on page 13

| | Year Ended December 31, 2006 | 2005 | 2004 |
|---|---|---|---|
| **Estimated proved reserves:** | | | |
| Oil (MBbls) | **126,185** | 106,173 | 101,287 |
| Natural gas (MMcf) | **288,826** | 278,367 | 168,484 |
| Oil equivalent (MBOE) | **174,322** | 152,568 | 129,369 |
| **Percentage of total MBOE:** | | | |
| Proved producing | **48%** | 40% | 39% |
| Proved nonproducing | **17%** | 16% | 16% |
| Proved undeveloped | **35%** | 44% | 45% |
| **Representative oil and gas prices [1]:** | | | |
| Oil – NYMEX | **$ 61.05** | $ 61.04 | $ 43.45 |
| Natural gas – Henry Hub | **5.63** | 10.08 | 6.18 |
| **Present values:[2]** | | | |
| Discounted estimated future net cash flow before income taxes ("PV-10 Value") (thousands) | **$ 2,695,199** | $ 3,215,478 | $ 1,643,289 |
| Standardized measure of discounted estimated future net cash flow after income taxes (thousands) | **1,837,341** | 2,084,449 | 1,129,196 |

(1) The prices as of each year-end were based on market prices in effect as of December 31 of each year, NYMEX prices per Bbl and Henry Hub cash prices per MMBtu, with the appropriate adjustments (transportation, gravity, BS&W, purchasers' bonuses, Btu, etc.) applied to each field to arrive at the appropriate corporate net price.

(2) Deter

## Field Summaries

Denbury operates in four primary areas: Louisiana, Eastern Mississippi, Western Mississippi and Texas. Our 16 largest fields (listed on the opposite page) constitute approximately 93% of our total proved reserves on a BOE basis and on a PV-10 Value basis. Within these 16 fields, we own a weighted average 92% 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 five primary field offices located in Houma, Louisiana; Laurel, Mississippi; McComb, Mississippi; Brandon, Mississippi; and Cleburne, Texas.

| | Proved Reserves as of December 31, 2006[1] | | | | | 2006 Average Daily Production | | |
|---|---|---|---|---|---|---|---|---|
| | Oil (MBbls) | Natural Gas (MMcf) | MBOEs | BOE % of total | PV-10 Value (000's) | Oil (Bbls/d) | Natural Gas (Mcf/d) | Average Net Revenue Interest |
| **Mississippi–$CO_2$ Floods** | | | | | | | | |
| Brookhaven | 18,987 | — | 18,987 | 10.9% | $353,406 | 833 | — | 82.0% |
| Mallalieu (East & West) | 13,582 | — | 13,582 | 7.8% | 457,200 | 5,210 | — | 76.6% |
| McComb/Olive | 12,717 | — | 12,717 | 7.3% | 297,449 | 1,177 | — | 77.0% |
| Eucutta | 10,313 | — | 10,313 | 5.9% | 186,229 | 47 | — | 83.5% |
| Little Creek & Lazy Creek | 3,696 | — | 3,696 | 2.1% | 90,592 | 2,739 | — | 83.3% |
| Smithdale and other | 2,872 | — | 2,872 | 1.7% | 71,560 | 64 | — | 79.3% |
| Total MS–$CO_2$ floods | 62,167 | — | 62,167 | 35.7% | 1,456,436 | 10,070 | — | 79.9% |
| **Other Mississippi** | | | | | | | | |
| Heidelberg (East & West) | 25,943 | 51,512 | 34,528 | 19.8% | 477,186 | 5,036 | 14,330 | 76.2% |
| Tinsley | 3,299 | 90 | 3,314 | 1.9% | 60,391 | 881 | 10 | 81.7% |
| Eucutta | 2,708 | — | 2,708 | 1.6% | 35,524 | 819 | 40 | 69.4% |
| S. Cypress Creek | 1,903 | 102 | 1,920 | 1.1% | 26,041 | 233 | 41 | 83.0% |
| Summerland | 1,662 | — | 1,662 | 0.9% | 20,556 | 445 | — | 74.4% |
| King Bee | 1,458 | — | 1,458 | 0.8% | 17,316 | 269 | — | 78.9% |
| Other Mississippi | 5,172 | 11,694 | 7,121 | 4.1% | 118,821 | 1,887 | 4,618 | 33.1% |
| Total Other Mississippi | 42,145 | 63,398 | 52,711 | 30.2% | 755,835 | 9,570 | 19,039 | 64.9% |
| **Louisiana** | | | | | | | | |
| S. Chauvin | 436 | 13,940 | 2,759 | 1.6% | 57,189 | 298 | 11,744 | 38.3% |
| Thornwell | 406 | 5,876 | 1,385 | 0.8% | 33,905 | 1,068 | 11,147 | 37.4% |
| Other Louisiana | 901 | 20,076 | 4,248 | 2.4% | 75,305 | 789 | 11,800 | 41.0% |
| Total Louisiana | 1,743 | 39,892 | 8,392 | 4.8% | 166,399 | 2,155 | 34,691 | 39.5% |
| **Texas** | | | | | | | | |
| Newark (Barnett Shale) | 11,606 | 182,812 | 42,075 | 24.1% | 243,474 | 106 | 28,525 | 75.0% |
| Other Texas | 179 | 669 | 290 | 0.2% | 1,552 | 8 | — | 79.9% |
| Total Texas | 11,785 | 183,481 | 42,365 | 24.3% | 245,026 | 114 | 28,525 | 75.1% |
| **Alabama** | | | | | | | | |
| Citronelle | 8,283 | — | 8,283 | 4.8% | 67,594 | 1,026 | — | 62.7% |
| Other Alabama | 7 | 1,978 | 337 | 0.2% | 3,165 | 1 | 727 | 30.5% |
| Total Alabama | 8,290 | 1,978 | 8,620 | 5.0% | 70,759 | 1,027 | 727 | 60.2% |
| **Other** | 55 | 77 | 67 | 0.0% | 744 | — | 93 | 0.1% |
| Company Total | 126,185 | 288,826 | 174,322 | 100.0% | $2,695,199 | 22,936 | 83,075 | 57.2% |

(1) The reserves were prepared using constant prices and costs in accordance with the guidelines of the SEC based on the prices received on a field-by-field basis as of December 31, 2006. The prices at that date were a NYMEX oil price of $61.05 per Bbl adjusted to prices received by field and a Henry Hub natural gas price average of $5.63 per MMBtu also adjusted to prices received by field.

# Producing the Future

at December 31, 2006 (i.e., significant incremental proved reserves are anticipated during 2007 and beyond). The proved oil reserves in our tertiary fields have a PV-10 Value of $1.46 billion at December 31, 2006, using constant NYMEX pricing of $61.05 per Bbl and we had an estimated PV-10 Value of our probable oil reserves in our tertiary fields of $3.3 billion using the same prices (on an unrisked basis, including the mid-point of the reserve range at Hastings but excluding Oyster Bayou and Fig Ridge). 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. Through December 31, 2006, we had a balance of approximately $198.7 million of unrecovered net cash flow for our $CO_2$ source assets.

## Jackson Dome

We believe that having sufficient $CO_2$ is one of the most important ingredients, if not the key ingredient, to our tertiary operations. We acquired our Jackson Dome $CO_2$ source field in February 2001, giving us control of most of the $CO_2$ supply in Mississippi, as well as ownership and control of the critical 183-mile NEJD $CO_2$ pipeline. Since February 2001, we have acquired two additional wells and drilled 11 additional $CO_2$ producing wells, significantly increasing our estimated proved $CO_2$ reserves from 800 Bcf at the time of acquisition to approximately 5.5 Tcf as of December 31, 2006, a 19% increase over year-end 2005 proved reserves of 4.6 Tcf. Today, we own every producing $CO_2$ well in the region. We plan to drill several additional $CO_2$ wells in the future, including up to three additional wells during 2007, to further increase our proven $CO_2$ reserves and to obtain additional $CO_2$ deliverability.

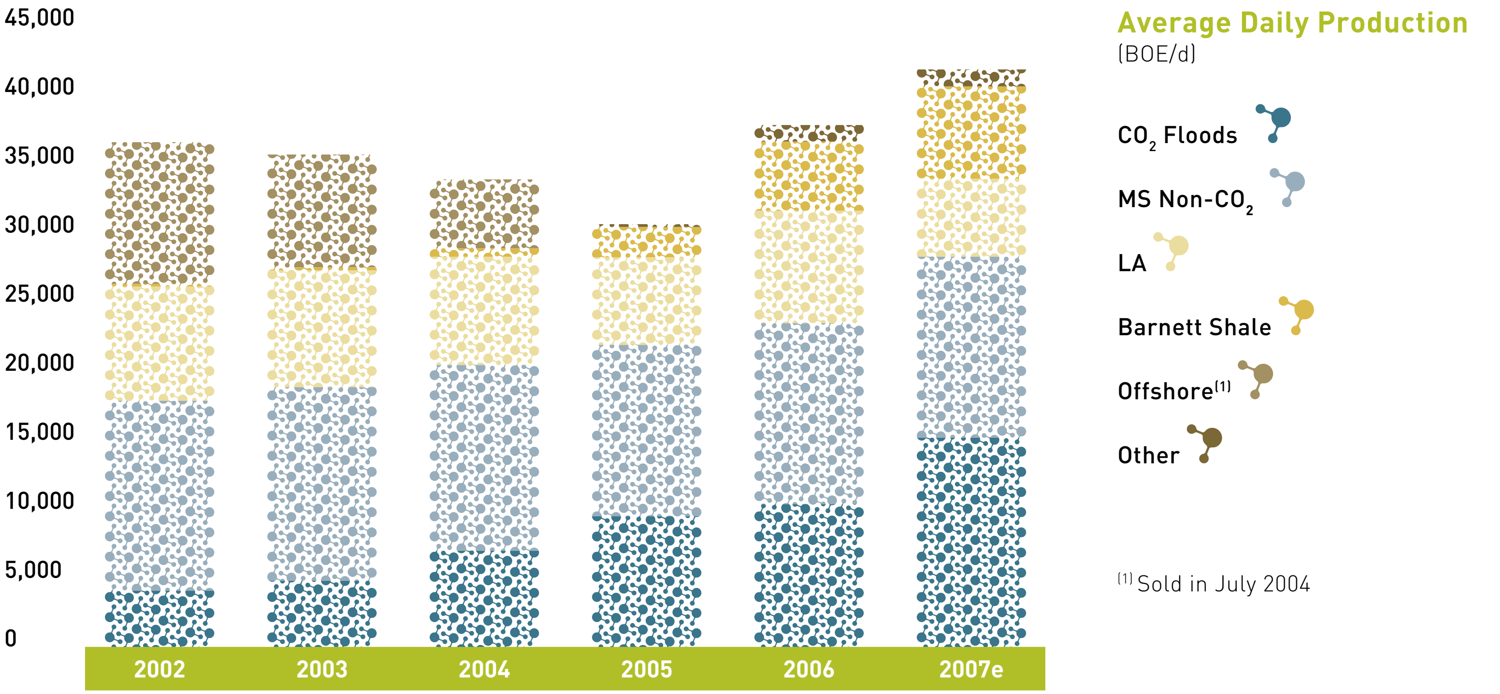
During the fourth quarter of 2006, we produced an average of 394 MMcf/d of $CO_2$. We sold an average of 78 MMcf/d of $CO_2$ to commercial

Our potential ability to tie these man-made $CO_2$ sources together with pipelines will give us a significant advantage over our competitors in our geographic area in acquiring additional oil fields and future potential man-made sources of $CO_2$.

users and we used an average of 316 MMcf/d for our tertiary activities. We estimate that our February 2007 daily $CO_2$ deliverability was in excess of 470 MMcf/d. By year-end 2007, we estimate that our planned tertiary operations and industrial customers will collectively require between 650 and 700 MMcf/d, but with our planned 2007 Jackson Dome projects, we expect to increase our $CO_2$ deliverability to between 700 MMcf/d and 800 MMcf/d by that date.

## Man-made $CO_2$ sources

We entered into an agreement and committed to purchase (if the plant is built) 100% of the $CO_2$ production from a man-made (anthropogenic) source of $CO_2$, from a planned petroleum coke gasification project, currently scheduled to be completed in 2010. This proposed Faustina plant, to be located near Donaldsonville, Louisiana, will convert petroleum coke into ammonia. As a byproduct of the process, large quantities of $CO_2$ will be produced, estimated to be around 200 MMcf/d. We plan to use this $CO_2$ in our tertiary operations to recover oil that may otherwise not be produced. In addition, our use of this $CO_2$ will also eliminate the release of this greenhouse gas into the Earth's atmosphere. The Faustina agreement allows us to add the potential equivalent volume of an additional one Tcf of $CO_2$ over the 15 year term of our contract. Construction of this plant has not yet begun, so we are not certain whether this plant will be built, although it currently appears likely. We are in discussions with several other entities that are considering building other types of coal or petroleum coke gasification plants. These plants may convert petroleum coke or coal into a variety of products including ammonia, methanol, synthetic diesel fuel, or electrical power generation. The cost of this man-made $CO_2$ will likely be higher than $CO_2$ from our natural source, but the location of these plants could mitigate some of the incremental cost of transportation. Further, we see these sources as a possible expansion of our natural Jackson Dome source, assuming they are economical, and we believe that our potential ability to tie these sources together with pipelines will give us a significant advantage over our




competitors in our geographic area in acquiring additional oil fields and future potential man-made sources of $CO_2$.

We talk about our tertiary oil operations by labeling operating areas or groups of fields as phases.

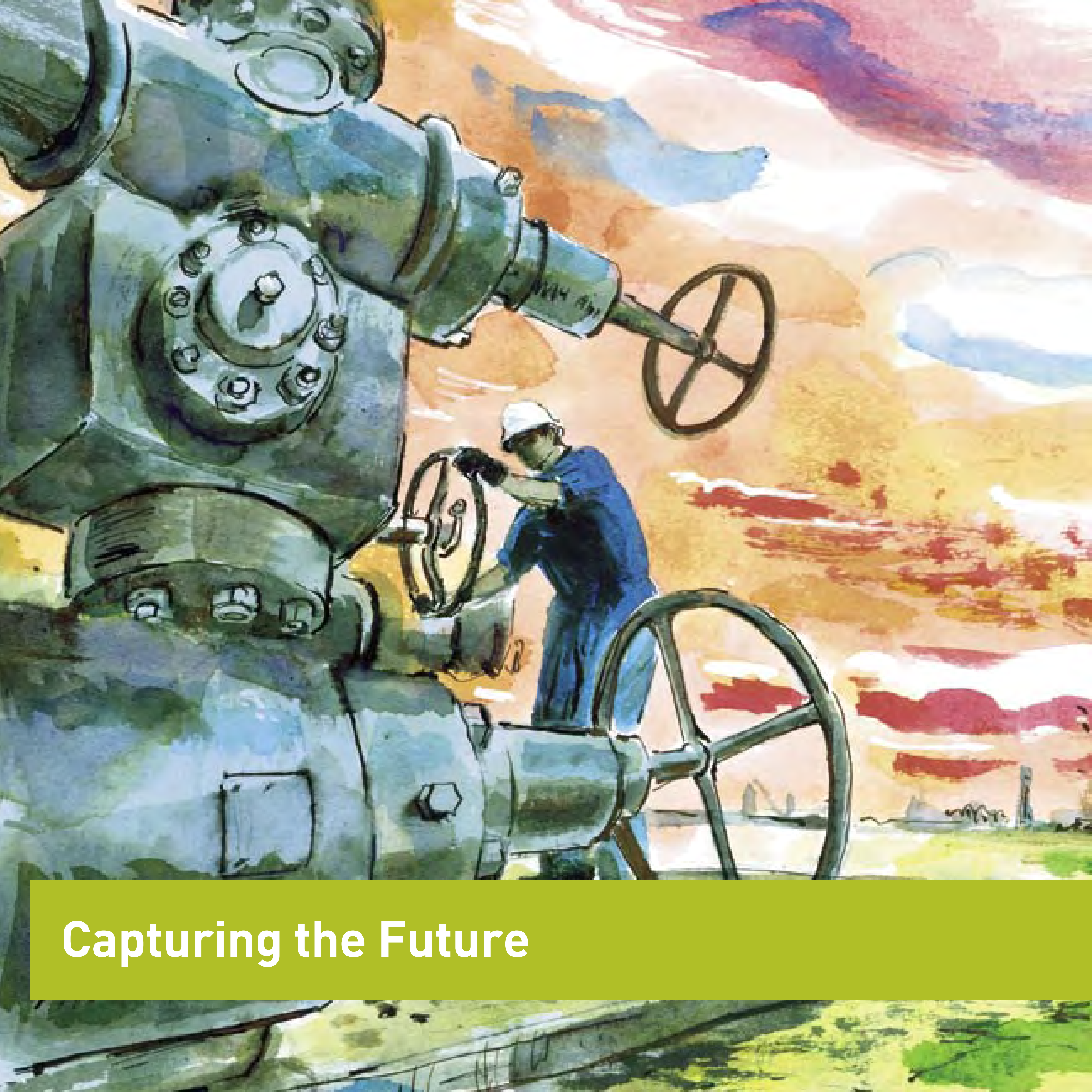
## Phase I

Phase I is in Southwest Mississippi and includes several fields along our 183-mile NEJD $CO_2$ pipeline. The most significant fields in this area are Little Creek, Mallalieu, McComb and Brookhaven.

# Seeing the World

What began as a small but effective strategy to extract more oil from mature fields in Mississippi using a large naturally occuring deposit of carbon dioxide near Jackson Dome has developed into a broader strategy throughout the Gulf Coast region and Texas.

Tinsley
Delhi
Jackson Dome
Davis
Quitman
Heidelberg
Martinville
Sandersville
Eucutta
Lake St. John
Brookhaven
Soso
Cypress Creek
Yellow Creek
Cranfield
Mallalieu
Olive
Little Creek
Smithdale
McComb
MISSISSIPPI
ALABAMA
UISIANA
Citronelle
Lockhart Crossing
Port Barre
Baton Rouge
Thornwell S
Donaldsonville
Iberia
Lake Arthur SW
Houma



# Capturing the Future

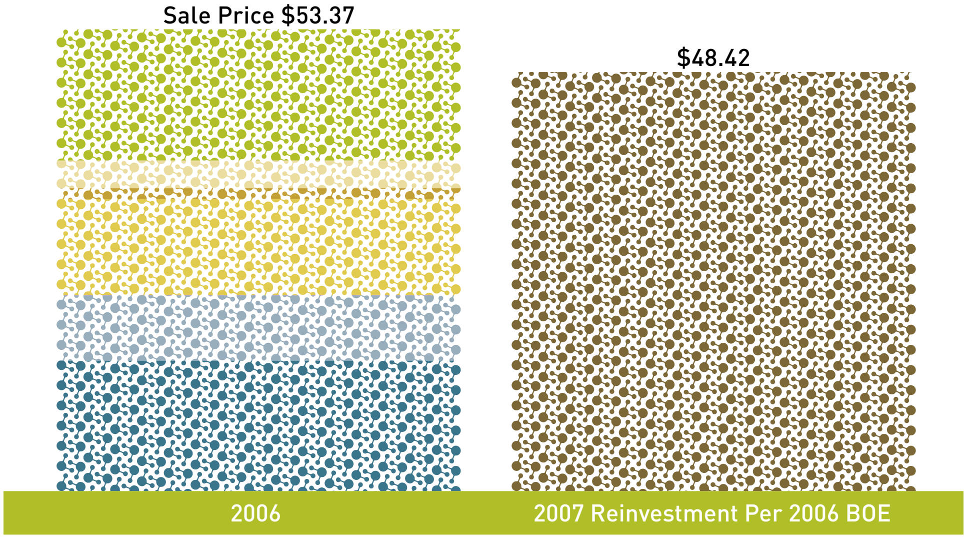
This was our first area of tertiary operations which began with the purchase of Little Creek in 1999, our tertiary recovery area with the most proven reserves (51.7 MMBbls), and from which we have derived virtually all of our tertiary production to date (15 MMBbls). We estimate that there are up to 15 MMBbls of additional potential reserves in this area, primarily from anticipated higher recovery rates, in addition to further expansion of existing floods and implementation of floods at smaller fields. We booked our first incremental recoverable amounts at Mallalieu Field in 2006, a field that had not been previously waterflooded, raising the estimated recoverable amount of original oil in place from 17% to 20%. We believe that we could ultimately recover in excess of 25% of the original oil in place from this field. This potentially higher recoverable amount represents a significant portion of the 15 MMBbls of incremental potential recoverable barrels that we believe are in this area.

During 2006, most of our work in Phase I was related to further expansion of the floods and facilities in existing fields. Production from this area averaged 9,817 Bbls/d in the fourth quarter of 2006 from this area, less than originally planned for 2006 primarily because our $CO_2$ injections during 2006 were significantly below forecasted amounts. This lower production was caused by a variety of factors which all led to delays in $CO_2$ injections: difficulties re-entering certain injection wells, which has required that some wells be redrilled; delays in getting permits and right-of-ways; and a general tightening of available materials and equipment in the industry. We also learned that we needed to increase injection pressure and/or stimulate the formation at certain fields in order to achieve our desired injection volumes. Further, delays in completing facilities at Jackson Dome, our source field, limited overall $CO_2$ volumes from time to time during 2006. We believe that these issues

**Where does our money go?**

(per 2006 BOE data)

| | |
|---|---|
| Operating | $15.17 |
| Administrative | $ 3.20 |
| Interest | $ 1.26 |
| DD&A | $11.11 |
| Taxes & Other | $ 7.55 |
| Profit | $15.08 |




have been corrected, or are in the process of being corrected, and during 2007 we will continue to expand existing floods, as well as initiate flooding at Lockhart Crossing, one of the smaller fields in Phase I.

## Phase II

Phase II includes our fields in East Mississippi. This area has only 10.5 MMBbls of tertiary proven reserves as of December 31, 2006 (virtually all at Eucutta Field), but has up to an estimated 67 MMBbls of incremental potential reserves from tertiary operations. In early 2006, we completed our Free State $CO_2$ pipeline from Jackson Dome to Eucutta Field and initiated flooding at three of our Phase II fields, Eucutta, Soso, and Martinville Fields. This area also includes one of our largest conventional fields, Heidelberg, a future tertiary flood candidate. Due to delays, we did not have any significant production response from this area during 2006, although we averaged over 800 Bbls/d from Phase II (from Eucutta and Martinville Fields) during the month of January 2007, based on preliminary estimates. Once we see significant response from Martinville and Soso Fields, we should be able to book significant proved reserves at these two fields. We are currently injecting over 100 MMcf/d of $CO_2$ into these three fields. During 2007, we will expand our operations at these three fields by starting additional injection patterns, and we expect our tertiary related oil production from Phase II to significantly increase during 2007.

## Phase III

Tinsley Field, Northwest of Jackson Dome, was the most significant field acquired in our $250 million January 2006 acquisition and is our Phase III project. Tinsley is one of the largest oil fields in the state of Mississippi and while it has no current proven tertiary oil reserves, we believe that it has in excess of 40 MMBbls of incremental potential recoverable oil reserves from tertiary operations. The acquisition of the field included an eight inch pipeline that at the time of acquisition was in natural gas service. We have reconditioned the pipeline for $CO_2$ service and initiated limited $CO_2$ injection in January 2007. During 2007, we plan to replace this line with a 24 inch, 31-mile line from Jackson Dome to Tinsley, with completion currently anticipated in the third or fourth quarter of 2007. We don't expect any significant production from Phase III until 2008.

## Phase IV

Phase IV includes Cranfield and Lake St. John Fields, two fields near the Mississippi/Louisiana border located west of our Phase I fields acquired during 2005. We believe that these two fields have over 30 MMBbls of potentially recoverable oil from tertiary operations. During 2006, we reached agreement with Southern Natural Gas Company to acquire a natural gas pipeline that runs from Gwinville Field in East Mississippi to the Western Mississippi border near Lake St. John Field in Louisiana. This pipeline crosses our existing NEJD 20 inch $CO_2$ pipeline in Southwest Mississippi and, once converted to $CO_2$ service, will allow us to transport $CO_2$ from the NEJD pipeline to Lake St. John and Cranfield Fields. We are in the process of building a small replacement natural gas pipeline to service

**Tinsley Field, Northwest of Jackson Dome, was the most significant field acquired in our $250 million January 2006 acquisition and is our Phase III project.**

During November 2006, we acquired an option to purchase between November 1, 2008 and November 1, 2009, Hastings Field, a strategically significant potential tertiary flood candidate located near Houston, Texas.

certain communities currently supplied by the acquired line, after which we can convert the acquired natural gas line to $CO_2$ service. We currently expect to have this completed by the fourth quarter of 2007.

### Phase V

Currently, Phase V is our last firmly scheduled phase and consists of Delhi Field, a Louisiana field we acquired in May 2006 for $50 million, plus a 25% reversionary interest to the seller after we have achieved $200 million in net operating revenue, as defined. We believe that Delhi Field has over 35 MMBbls of potentially recoverable oil from tertiary operations. Before flooding can commence, we need to extend the $CO_2$ line to be built to Tinsley Field in 2007 (as more fully discussed in Phase III above) by building a 68 mile 20 inch extension to Delhi Field with completion for this segment currently anticipated during the first half of 2008. Our goal is for initial oil production from tertiary operations to begin during 2009.

### Future Citronelle Phase

We also plan to ultimately flood Citronelle Field, a field in Southwest Alabama, acquired in our $250 million January 2006 acquisition, which we believe has over 25 MMBbls of potentially recoverable oil from tertiary operations. However, in order to flood this field, we will need to extend our Free State $CO_2$ Pipeline from Eucutta Field another 60 to 70 miles to Citronelle Field.

### Texas Gulf Coast Phase

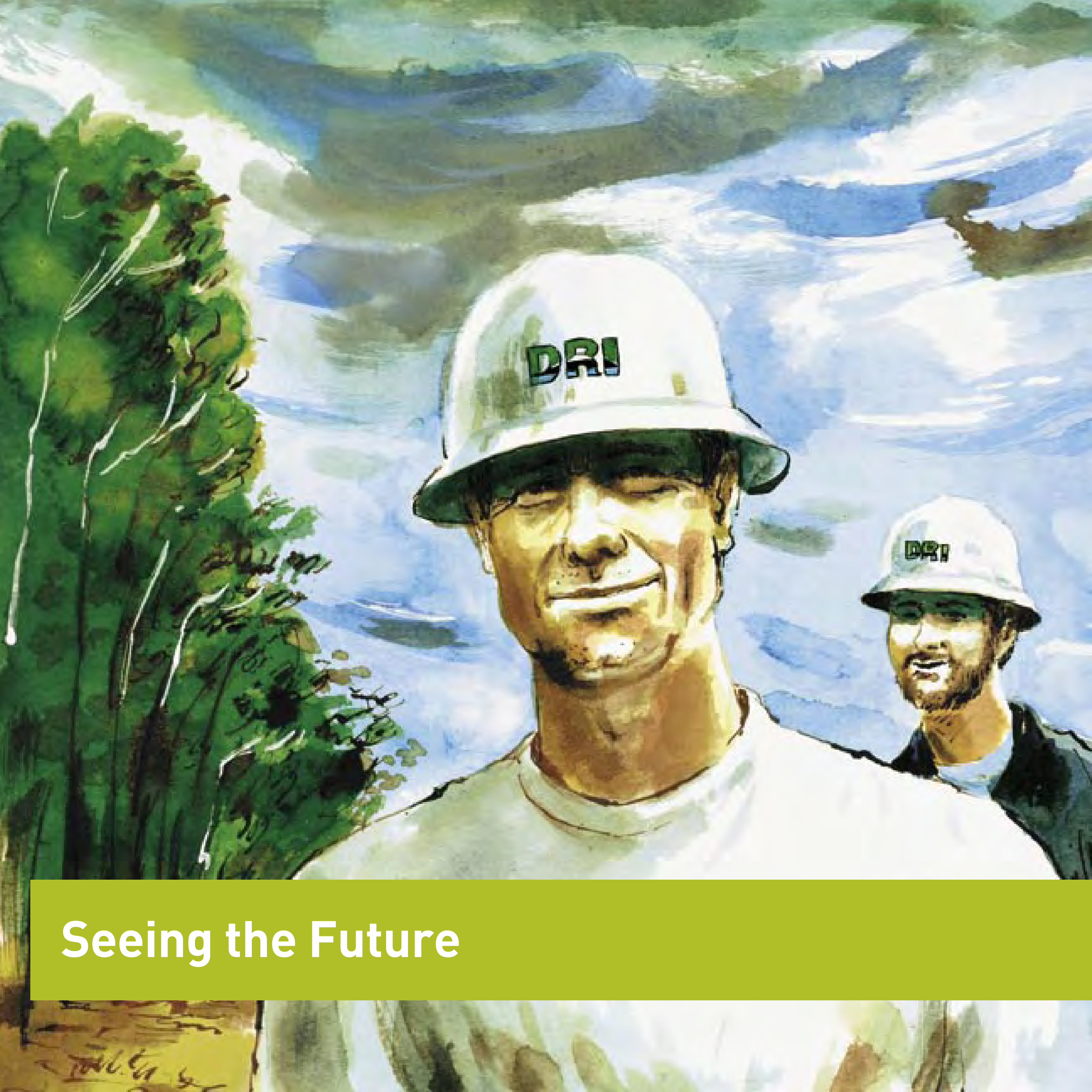
During November 2006, we acquired an option to purchase, between November 1, 2008 and November 1, 2009, Hastings Field, a strategically significant potential tertiary flood candidate located near Houston, Texas. The purchase price for the conventional proved reserves will be determined at the time the option is exercised, either by agreement or by a pre-designated independent petroleum engineering firm. As consideration for the purchase option, we made an upfront payment of $37.5 million and are required to make additional payments totaling $12.5 million during 2007 and

2008. None of the option payment amounts will be credited against the purchase price if we exercise the option.

We believe that Hastings Field possesses between 50 and 90 MMBbls of reserve potential from $CO_2$ tertiary floods, more reserve potential than any other single field in our inventory. We plan to build a pipeline to transport $CO_2$ to this field. Based on preliminary estimates, this pipeline is expected to cost between $450 million and $650 million, although this cost could vary significantly depending on the ultimate size of the pipeline, its pressure rating, its specific route, and other variables, all of which are unknown at this time. We are initiating studies related to construction of this line, with a goal of having it installed and operational during 2009. We anticipate initially transporting $CO_2$ from our natural source at Jackson Dome, but ultimately plan to use man-made (anthropogenic) sources of $CO_2$ for this tertiary operation. Based on preliminary 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 $CO_2$ pipeline.

The Hastings Field is the first significant strategic addition in this area, giving us an anchor field in this region. We have already expanded our field inventory in this area as we announced in February 2007, an agreement to purchase two important fields with tertiary potential and a few smaller fields in this same general area for $42 million, an acquisition expected to close in March 2007. We believe that two of these fields, Oyster Bayou and Fig Ridge, have significant tertiary reserve potential estimated to be between 30 and 40 MMBbls. Since our $CO_2$ pipeline to this area is not expected to be completed until 2009, our goal is to continue to pursue the acquisition of other fields in this area, which will help reduce the cost of $CO_2$ for each field by fully utilizing the proposed pipeline and thereby reducing our transportation cost per Mcf.

**We believe that Hastings Field possesses between 50 and 90 MMBbls of reserve potential from $CO_2$ tertiary floods, more reserve potential than any other single field in our inventory.**




# Seeing the Future

## Texas and the Barnett Shale

We currently own about 53,800 net acres of leases in the Barnett Shale area in North Central Texas, about 19,600 net acres of which is in the more tested northern area of Parker and Wise Counties, with the remainder in Erath and adjoining southern counties. We acquired our initial acreage in this area in 2001 and did only limited development until 2005. Through December 31, 2006, we have spent a total of $267.2 million on the Barnett Shale area and have received $90.1 million in net operating income (revenue less operating expenses), or net negative cash flow of $177.1 million. As of December 31, 2006, we had approximately 252.4 Bcfe of proved reserves in the Barnett Shale area with a PV-10 Value of approximately $243.5 million, using December 31, 2006, Henry Hub indicative cash pricing of $5.63 per MMBtu.

We continue to refine our completion and fracturing techniques, including an analysis of the best number of fracture treatments to adequately stimulate the entire length of the lateral sections of our horizontal wells, which can exceed 4,000 feet. During 2006 we drilled an additional 46 horizontal wells, increasing our net Barnett Shale production from approximately 18.3 MMcfe/d in the fourth quarter of 2005 to approximately 35.4 MMcfe/d during the fourth quarter of 2006. During 2006, we finalized the acquisition and interpretation of our 3-D seismic data over our entire northern acreage position, 90 to 100 square miles and initiated a 3-D shoot of the southern acreage. The 3-D seismic data helps us better locate our wells so that we encounter less faulting and underground sink holes, which have been associated with fracture stimulations into zones outside of the Barnett Shale that are typically water bearing. We expect production in this area to grow significantly during 2007 as we plan to drill approximately 35 to 40 horizontal wells, all of which are scheduled for Parker County. Including seismic costs and pipeline infrastructure costs, our planned 2007 capital expenditures in the Barnett Shale area are estimated to be $122 million of our current $650 million exploration and development budget.

We have been active in East Mississippi since Denbury was founded in 1990 and are by far the largest producer in the basin.

At this time we are still evaluating the 2006 drilling and completion work in our southern acreage, primarily Erath County. The initial results do not look very encouraging as we drilled five wells, completing three, none of which have been economic. We elected not to complete the last two wells pending a re-analysis of all of our results to date.

## East Mississippi (non-$CO_2$ properties)

We have been active in East Mississippi since Denbury was founded in 1990 and are by far the largest producer in the basin. Historically, this has been our area with the highest production and most proved reserves, representing production of approximately 12,808 BOE/d during the fourth quarter of 2006 (35% of our Company total) and proved reserves of 52.7 MMBOE as of December 31, 2006 (30% of our Company total). Since we have generally owned these East Mississippi properties longer than properties in our other regions, they tend to be more fully developed, and although most are targeted for tertiary operations in the future, currently we are conducting tertiary operations on only three fields here (Soso, Martinville and Eucutta Fields). Production from our East Mississippi fields has been relatively consistent over the last three years, averaging 13,085 BOE/d in 2004, 12,072 BOE/d in 2005 and 12,743 BOE/d during 2006. For 2007, we expect our budget in this region for conventional operations to be around $50 million, about the same as in 2006, representing approximately 8% of our current 2006 exploration and development budget of $650 million.

## Heidelberg Field

The largest field in the region and one of our largest fields corporately is Heidelberg Field, which for the fourth quarter of 2006 produced an average of 7,444 BOE/d, 2% more than the 2005 average of 7,312 BOE/d. Heidelberg Field was acquired from Chevron in December 1997 and was producing approximately 2,800 BOE/d at that time.

The majority of the oil production at Heidelberg is from six waterflood units that produce from the Eutaw formation (at approximately 4,400 feet). Most of our recent development at Heidelberg has been in the Selma Chalk, a natural gas reservoir at around 3,700 feet, making Heidelberg our second largest gas field. We have steadily developed the Selma Chalk since 2001, drilling from 13 to 20 wells per year, increasing the natural gas production at Heidelberg to a peak quarterly average of 15.8 MMcf/d in the fourth quarter of 2004, with average natural gas production of 14.3 MMcf/d during 2006. Following our initial success in 2005 drilling a horizontal well, during 2006 we drilled 12 Selma Chalk wells, four of which were horizontal wells, and we plan to drill 13 horizontal wells here during 2007.

## South Louisiana

We own interests in the land and marshes of south Louisiana, a region that produces primarily natural gas. Production from this area averaged 39.4 MMcfe/d net to our interest in the fourth quarter of 2006, a slight increase from our 2005 production average of 37.0 MMcfe/d. Production was as high as 51.7 MMcfe/d during the second quarter of 2006 following the completion of several new wells drilled in late 2005 and early 2006, but has declined significantly from that peak as a result of the relatively rapid depletion for wells in this area. During 2006, we spent approximately $64.7 million (excluding acquisitions) in this region, approximately 13% of our total exploration and development expenditures, drilling approximately 12 wells, primarily in the Cameron, Jefferson Davis, and Terrebonne Parish areas. For 2007, our spending is expected to be approximately $40 million or 6% of our currently planned $650 million exploration and development budget, significantly less than our 2006 expenditures in this area.

In 2007, we plan to drill approximately six exploratory wells in Southern Louisiana and four to five development wells. We are currently drilling our second Gumbo well, a 19,000+ foot well testing the Rob L sands, on which we expect to reach total depth early in the second quarter. Our first well in this area apparently encountered an isolated reservoir area that we do not believe is in communication with the large feature we see on seismic. We believe that this second well could have significant reserve potential.

**We are currently drilling our second Gumbo well, a 19,000+ foot well testing the Rob L sands, on which we expect to reach total depth early in the second quarter. We believe that this well could have significant reserve potential.**

**Corporate Headquarters**
Denbury Resources Inc.
5100 Tennyson Pkwy, Ste. 1200
Plano, Texas 75024
T: 972.673.2000
F: 972.673.2150

**Field Offices**

| | |
|---|---|
| Brandon, MS: | T: 601.824.1198 |
| Cleburne, TX: | T: 817.645.8100 |
| Laurel, MS: | T: 601.428.1998 |
| Little Creek, MS: | T: 601.276.2147 |
| Houma, LA: | T: 985.857.9215 |

**Data Requests**
Cynthia Rodriguez

**Investor Relations**
Laurie Burkes
www.denbury.com

**Questions RE: Press Releases and Stockholder Reports**
Gareth Roberts
President & Chief Executive Officer

Phil Rykhoek
Senior Vice President
& Chief Financial Officer

Laurie Burkes
Investor Relations Manager

**Engineering:**
Tracy Evans, Senior Vice President, Reservoir Engineering

**Finance:**
Phil Rykhoek, Senior Vice President & Chief Financial Officer

**Operations:**
Robert Cornelius, Senior Vice President, Operations

**Accounting:**
Mark Allen, Vice President & Chief Accounting Officer

**Marketing:**
Dan Cole, Vice President, Marketing

**Exploration:**
Jim Sinclair, Vice President, Exploration and Geosciences

**Land:**
Ray Dubuisson, Vice President, Land

**Cautionary Note to U.S. Investors:**
The United States Securities and Exchange Commission permits oil and natural gas companies, in their filings with the SEC, to disclose only
proved reserv
under existi
potential reserves
including in filings with the SEC.

**Forward-Looking Statements:**
The data contained in this annual report that are not historical facts are forward-looking statements that involve a number of risks and uncertainties. Such statements may relate to, among other things, capital expenditures, drilling activity, development activities, production efforts and volumes, asset values, proved reserves, potential reserves and anticipated production growth rates in our $CO_2$ models, production and expenditure estimates, availability and cost of equipment and services, and other enumerated reserve potential. These forward-looking statements are generally accompanied by words such as "estimated", "projected", "potential", "possible", "anticipated", "forecasted" or other words that convey the uncertainty of future events or outcomes. These statements are based on management's current plans and assumptions and are subject to a number of risks and uncertainties as further outlined in our most recent 10-K and 10-Q. Therefore, the actual results may differ materially from the expectations, estimates or assumptions expressed in or implied by any forward-looking statement made by or on behalf of the Company.

Financials Begin

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

# 2006 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, 2006

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. (See definition of "accelerated filer and large accelerated filer" in Rule 12-b2 of the Exchange Act). (Check one):
Large accelerated filer _X_ Accelerated filer ___ Non-accelerated filer ___

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 $3,417,875,900.

The number of shares outstanding of the registrant's Common Stock as of January 31, 2007, was 120,470,488.

**DOCUMENTS INCORPORATED BY REFERENCE**

| Document: | Incorporated as to: |
|---|---|
| *1. Notice and Proxy Statement for the Annual Meeting of Shareholders to be held May 15, 2007.* | *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 $CO_2$. |
| 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 $CO_2$. |
| 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 production and future development costs and abandonment, using prices and costs in effect at the determination date, and before income taxes, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the Securities and Exchange Commission. |
| 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. See* **www.sec.gov/divisions/corpfin/forms/regsx.htm#gas** *for the complete definition.*

## 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 Louisiana, Mississippi, Alabama, and Texas. 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, 2006, we had 596 employees, 390 of whom were employed in field operations or at the field offices. Our employee count does not include the approximately 190 employees of Genesis Energy, Inc. as of December 31, 2006, as its employees exclusively carry out the business activities of Genesis Energy, L.P., which we do not consolidate in our financial statements (see Note 1 to the Consolidated Financial Statements).

#### 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. (new entity). Stockholders' ownership interests in the business did not change as a result of the new structure and shares of the Company remain publicly traded 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;
- acquire properties where we believe additional value can be created through a combination of exploitation, development, exploration and marketing, including secondary and tertiary operations;
- 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 reducing cost; and
- maintain a highly competitive team of experienced and incentivized personnel.

### 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 Gas Operations**

Our $CO_2$ Assets

During 2006, we concentrated on implementing new tertiary floods in our Phase II fields, Eucutta, Soso and Martinville Fields, while continuing to develop our Phase I fields Little Creek, Mallalieu, McComb and Brookhaven. We increased our potential tertiary flood candidates during 2006 with the acquisition of Tinsley Field (Phase III) and Delhi Field (Phase V), and an option to purchase Hastings Field, adding to our inventory of future tertiary floods. Our tertiary operations are our principal focus and our core assets. During the last seven years, we have learned a considerable amount about tertiary operations and working with carbon dioxide ("$CO_2$") and our knowledge continues to grow. We like these tertiary operations because (i) $CO_2$ investments provide a reasonable rate of return, even at relatively low oil prices, (ii) tertiary flooding exhibits a lower risk profile, and (iii) to date, in our region of the United States, we have not encountered any industry competition. Generally, from the Texas Gulf Coast to Florida, there are no known significant natural sources of carbon dioxide except our own, and these large volumes of $CO_2$ are the foundation for our entire tertiary program.

$CO_2$ 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 $CO_2$, which to our knowledge is limited to a few geological basins, one of which is our source near Jackson, Mississippi. Further, the most $CO_2$ 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 3% or 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 initially proved to be successful in recovering significant amounts of oil, commodity prices at that time made the projects 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 (EOR) 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 in Mississippi, followed by our acquisition of Jackson Dome 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 niche play.

We talk about our tertiary operations by labeling operating areas or groups of fields as phases. Phase I is in Southwest Mississippi and includes several fields along our 183-mile $CO_2$ pipeline that we acquired in 2001. The most significant fields in this area are Little Creek, Mallalieu, McComb and Brookhaven. Phase II, which we just started with the 2006 completion of our $CO_2$ pipeline to East Mississippi, includes Eucutta, Soso, Martinville and later, Heidelberg Fields. With the properties acquired in our January 2006 acquisition, we have labeled the planned operations at Tinsley Field, Northwest of Jackson Dome, as Phase III. Phase IV includes Cranfield and Lake St. John Fields, two fields near the Mississippi/ Louisiana border acquired in 2005 and which are located west of the Phase I fields. Phase V is Delhi Field, a Louisiana field we acquired in May 2006. We also plan to ultimately flood Citronelle Field, another field acquired in 2006, and Hastings Field, a field on which we recently acquired a purchase option. We have not yet labeled these two fields as a specific phase.

*Jackson Dome.* In February 2001, we acquired approximately 800 Bcf of proved producing $CO_2$ reserves for $42.0 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 additional wells and drilled 11 additional $CO_2$ producing wells, significantly increasing our estimated proved $CO_2$ reserves to approximately 5.5 Tcf as of December 31, 2006, which is more than enough for our existing and currently planned phases of operations. The estimate of 5.5 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 4.5 Tcf and is included in the evaluation of proven $CO_2$ reserves prepared by DeGolyer & 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 for both of these uses. Today, we own every producing $CO_2$ well in the region. Although our current proven 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 needed. In order to obtain additional $CO_2$ deliverability, we plan to drill several additional $CO_2$ wells in the future, including up to three additional wells during 2007.

During the fourth quarter of 2006, we produced an average of 394 MMcf/d of $CO_2$. We sold an average of 78 MMcf/d of $CO_2$ to commercial users and we used an average of 316 MMcf/d for our tertiary activities. We estimate that our current daily $CO_2$ deliverability is around 470 MMcf/d. By year-end 2007, we estimate that our planned tertiary operations will require between 650 and 700 MMcf/d, but with our planned 2007 Jackson Dome projects, we expect to increase our $CO_2$ deliverability to between 700 MMcf/d and 800 MMcf/d by that time. Our geoscientists are using a 100 square mile 3-D seismic survey to locate additional structures that are expected to contain $CO_2$. We plan to continue our $CO_2$ drilling activity in 2007 and beyond, as our $CO_2$ deliverability needs will continue to grow as we expand our planned tertiary projects.

*Man-made $CO_2$ sources.* We entered into an agreement and committed to purchase (if the plant is built) 100% of the $CO_2$ production from a man-made (anthropogenic) source of $CO_2$, a planned petroleum coke gasification project scheduled to be completed in 2010. This Faustina plant, proposed to be located near Donaldsonville, Louisiana, will convert petroleum coke into ammonia. As a byproduct of the combustion, large quantities of $CO_2$ will be produced, estimated to be around 200 MMcf/d. We plan to use this $CO_2$ in our tertiary operations to recover oil that may otherwise not be produced. In addition, our use of this $CO_2$ will also eliminate the release of this greenhouse gas into the earth's atmosphere. The Faustina agreement allows us to add the potential equivalent volume of an additional one Tcf of $CO_2$ over the term of our contract. Construction of this plant has not yet begun, so we are not certain whether this plant will be built, although it appears likely. We are in discussions with several other entities that are considering other types of coal or petroleum coke gasification plants. These plants may convert petroleum coke or coal into a variety of products including ammonia, methanol, synthetic diesel fuel, or electrical power generation. The cost of this man-made $CO_2$ will likely be higher than $CO_2$ from our natural source, but the location of these plants could mitigate some of the incremental cost of transportation. Further, we see these sources as a possible expansion of our natural Jackson Dome source, assuming they are economical, and we believe that our potential ability to tie these sources together with pipelines will give us a significant advantage over our competitors in our geographic area in acquiring additional oil fields and future potential man-made sources of $CO_2$.

*$CO_2$ pipelines.* We acquired the NEJD 183-mile $CO_2$ pipeline that runs from Jackson Dome to near Donaldsville, Louisiana as part of the 2001 acquisition (see above). During the first quarter of 2006, we completed the 20", 86-mile Free State Pipeline, which we are initially using to transport $CO_2$ to our three new Phase II fields in East Mississippi (Eucutta, Soso, and Martinville). Completion of this line was a significant accomplishment for our team and expands our $CO_2$ tertiary recovery technology to many potentially significant reservoirs in the eastern part of the state.

During 2006, we reached agreement with Southern Natural Gas Company to acquire a natural gas pipeline that runs from Gwinville Field to near Lake St. John Field in Louisiana. This pipeline crosses our existing NEJD 20" $CO_2$ pipeline in Southwest Mississippi, and once converted to $CO_2$ service, will allow us to transport $CO_2$ from the NEJD pipeline to Lake St. John and Cranfield Fields, both acquired in 2005 (our planned Phase IV). We are in the process of building a small replacement natural gas pipeline to service certain communities currently supplied by the acquired line, after which we can convert the acquired natural gas line to $CO_2$ service. We expect to have this completed by the fourth quarter of 2007.

The 2006 acquisition of Tinsley Field included an eight-inch pipeline, previously being used for natural gas sales and storage, from our Jackson Dome area to the field. We converted the natural gas line to a $CO_2$ pipeline and in early 2007 began using it to transport $CO_2$ to Tinsley Field, albeit in limited volumes. During 2007, we plan to construct a 24", 31 mile line from Jackson Dome to Tinsley Field, with completion anticipated in the third or fourth quarter of 2007. We plan to further extend this line by building a 68 mile 20" extension from Tinsley Field to Delhi Field with completion for this segment anticipated during the first half of 2008.

In late 2006, we purchased an option to acquire Hasting Field, a potential tertiary flood located near Houston, Texas. We plan to build a pipeline to transport $CO_2$ to this field from the southern end of our existing $CO_2$ pipeline that terminates near Donaldsonville, Louisiana, estimated at between 280 and 300 miles. Based on very preliminary estimates, this pipeline is expected to cost between $450 million and $650 million, although this cost could vary significantly depending on the ultimate size of the pipeline, its pressure rating, its specific route, and other variables, all of which are unknown at this time. We are initiating studies related to construction of this line, with a goal of having it installed and operational during 2009. We anticipate initially transporting $CO_2$ from our natural source at Jackson Dome, but ultimately plan to use man-made (anthropogenic) sources of $CO_2$ for this tertiary operation.

*Overall economics.* Initially, our tertiary operations were economic at oil prices below $20 per Bbl, although the economics have always varied by field. Our costs have escalated during the last few years due to general cost inflation in the industry, raising our current economic oil price to around $30 per Bbl, again dependent on the specific field. 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, 2006, was approximately $8.50 per BOE. Currently, we forecast that these costs will range from $5 to $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, etc. Our operating costs for tertiary operations are expected to range from $13 to $15 per BOE over the life of each field (at today's prices), again depending on the field itself.

Oil quality is another significant factor that impacts the economics. In Phase I (Southwest Mississippi), the light sweet oil produced from our tertiary operations receives near NYMEX prices, while the average discount to NYMEX for the lower quality oil produced from the fields in Phase II (East Mississippi), some of which we started flooding during 2006, was $13.51 per BOE during 2006, a differential that is significantly higher than our historical corporate averages and one that appears to increase as oil prices increase.

While these economic factors have wide ranges, our rate of return from these operations has generally been better than the rate of return on our traditional oil and gas operations and entail less risk, 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 and reserve 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 spend approximately $70 million in 2007 in the Jackson Dome area with the intent to add additional $CO_2$ reserves and deliverability for future operations. Approximately $60 million in capital expenditures is budgeted in 2007 for our Phase II properties (East Mississippi) and approximately $200 million for Phase III properties (Tinsley), plus an additional $70 million for properties in other phases, making our combined $CO_2$ related expenditures just over 60% of our $650 million 2007 capital budget.

**Our Tertiary Oil Fields with Proven Tertiary Reserves**

At December 31, 2006, we had total tertiary-related proved oil reserves of approximately 62.2 MMBbls, consisting of 3.7 MMBbls at Little Creek Field (and surrounding smaller fields), 13.6 MMBbls at Mallalieu Field, 12.7 MMBbls at McComb Field, 19.0 MMBbls at Brookhaven Field, 2.7 MMBbls at Smithdale Field, 10.3 MMBbls at Eucutta Field and 0.2 MMBbls at Martinville Field. 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 10,028 Bbls/d during the fourth quarter of 2006. We expect this production to continue to increase for several years as we expand our tertiary operations to additional fields.

With regard to our proven tertiary reserves, 2006 was a transition year for us, as we added only 6.0 MMBbls of tertiary-related proved oil reserves during the year, primarily incremental oil reserves at McComb and Mallalieu Fields (both Phase I). Previously, we booked most proven tertiary oil reserves near the start of a project as almost all the oil fields in Phase I were analogous to Little Creek Field (our first flood) and thus it was not necessary to have an oil production response to the $CO_2$ injections before they were considered proven. Conversely, our new floods (after Phase I) are not analogous (for the most part), as the tertiary floods will be in different geological formations. Therefore, for these new phases, there must be an oil production response to the $CO_2$ injections before we can recognize proven oil reserves, even though we believe that these formations have a similar risk profile. Since many of our Phase II projects were delayed during 2006, the production response needed to record any significant incremental tertiary oil reserves in this new area was delayed. We anticipate booking significant amounts of proven tertiary oil reserves during 2007 and beyond, although the magnitude will depend on our progress with Phases III and IV, two areas we plan to initiate development of during 2007, and the response from our new Phase II projects.

*Mallalieu Field.* The Mallalieu Field consists of two fields, West Mallalieu and the smaller East Mallalieu fields. Combined they are our most prolific tertiary flood, producing in excess of 4,994 Bbls/d for the fourth quarter 2006. In contrast to many of our existing fields, West Mallalieu Field was not waterflooded prior to $CO_2$ injection. Therefore, we believe that the tertiary recovery of oil from West Mallalieu Field as a result of $CO_2$ injection could approach 25% of the original oil in place. During 2006, we increased our proved reserves in this area, raising our estimated recovery factor from 17% to 20% for these fields, based on production performance to date. A total of $27.6 million was invested in this field during 2006 to drill, re-enter or recomplete wells in efforts to improve production. During 2007, we plan to expand the Mallalieu production facilities to accommodate the expected production growth. Reservoir modeling indicates the field may be producing in excess of 6,500 Bbls/d by the fourth quarter of 2007.

From inception through December 31, 2006, we had net positive cash flow (revenue less operating expenses and capital expenditures) from Mallalieu Field of $139.3 million, plus the fields have a PV-10 Value of $457.2 million, using December 31, 2006, NYMEX pricing of $61.05 per barrel.

*McComb and Smithdale Fields.* We commenced tertiary recovery operations in 2003 at McComb Field and started injecting $CO_2$ late that year. Significant development occurred during 2004 and 2005 as we expanded the nearby Olive Field $CO_2$ facility to handle the processing of McComb's produced oil, water and $CO_2$ and developed an additional four injection patterns. The first production response occurred in the second quarter of 2004 and has gradually increased since that time, averaging 1,463 Bbls/d in the fourth quarter of 2006. During 2006, we continued the expansion of our operations within McComb Field and further expanded the production facilities. Although we have encountered injection issues during 2006, which limited our $CO_2$ injections at McComb, by the second quarter of 2007 we expect to have all the necessary equipment installed, which we believe will eliminate the injection issues. In addition, we are injecting $CO_2$ at the nearby, much smaller, Smithdale Field utilizing the same $CO_2$ facilities. We started injecting $CO_2$ at Smithdale in the second quarter of 2005, although our production through December 31, 2006 has generally been less than 100 Bbls/day.

From inception through December 31, 2006, 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 $91.2 million, although the fields have a PV-10 Value of $370.7 million, using December 31, 2006, NYMEX pricing.

*Brookhaven Field.* Our first tertiary $CO_2$ production response at Brookhaven Field occurred during the fourth quarter of 2005, with oil production rates averaging 125 Bbls/d during the fourth quarter of 2005. Production rates continued to increase throughout 2006 as additional patterns were developed. Production during the fourth quarter of 2006 increased only slightly from third quarter 2006 rates, as $CO_2$ injection rates were less than initially planned. Incremental work on $CO_2$ injection wells was required to improve injection rates and to ensure the $CO_2$ was entering the proper intervals. Additional injection pumps were installed on certain wells to increase injection rates. Oil production during the fourth quarter of 2006 averaged 1,014 Bbls/d.

From inception through December 31, 2006, 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 Brookhaven of $50.9 million, although the field has a PV-10 Value of $353.4 million attributed to the tertiary recovery reserves, using December 31, 2006, NYMEX pricing.

*Little Creek Field.* During the fourth quarter of 2006, production averaged 2,279 Bbls/d (including Lazy Creek). Production at Little Creek Field began declining in 2006 and is expected to continue to decline over the next several years. 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. From inception through December 31, 2006, 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 $127.2 million, plus the fields have a PV-10 Value of $90.6 million, using December 31, 2006, NYMEX pricing.

*Eucutta Field.* Eucutta Field is the only field in East Mississippi (Phase II) that currently has significant proven tertiary oil reserves. This field is analogous to Heidelberg Field in that the majority of its historical production was produced from the Eutaw formation. The Eutaw formation at Eucutta was unitized for water flooding in 1966 and has gone through several stages of development. 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, with the first minor tertiary oil production during the fourth quarter of 2006. Our plans for 2007 include the development of the remaining patterns and expansion of our $CO_2$ facilities. At December 31, 2006 we had 10.3 MMBbls of proved reserves in the Eucutta field attributable to the $CO_2$ flood. The proved reserve estimate is based on a 13% recovery factor, lower than was achieved in the pilot program in the 1980s, and therefore we expect to have upward reserve increases in the future.

*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 essentially completed the development of the Mooringsport sand during 2006. During the fourth quarter of 2006, the first well responded, although the average rate for the quarter was only 24 Bbls/d. The tertiary oil rate has increased to approximately 400 Bbls/d during the month of January 2007. The second reservoir, the Rodessa, although smaller in size, has similar reservoir characteristics to the Mooringsport. We initiated injection into the Rodessa with three injection wells during 2006. We have not seen $CO_2$ response to date from the Rodessa.

The Wash Fred 8500' reservoir in the Martinville Field contains a low oil gravity (thick oil), 15 API, which will not develop miscibility with $CO_2$ at reservoir conditions. Denbury has several fields with similar 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 initiated $CO_2$ injection during the first quarter of 2006 at the crest of the structure. Although we will not achieve miscibility, the injection of $CO_2$ is expected to swell the oil, decrease the oil viscosity, and displace the water and oil downward in the reservoir to the adjacent producing wells and result in incremental oil production. Well bore issues delayed the implementation of this flood during 2006, but we are currently injecting $CO_2$ and observing the production from offset wells to determine what effect the $CO_2$ will have on oil and water production. The success of this flood would provide the impetus to look at a whole new array of fields that have historically not been considered for $CO_2$ injection, although there can be no assurance that this technique will be successful or economic.

**Our Tertiary Oil Fields without Proven Tertiary Reserves**

During 2007, we plan to commence tertiary operations at a small field, Lockhart Crossing (Phase I), our first Louisiana flood, and Cranfield Field in West Mississippi (Phase IV), and install the pipeline necessary to deliver $CO_2$ to Delhi Field (Phase V) so that injection can begin there in 2008. We initiated $CO_2$ injections at Tinsley Field (Phase III) in January 2007, although in very limited amounts, with more significant development expected there when the larger, replacement $CO_2$ pipeline to Tinsley is completed, which we anticipate will be in the fourth quarter of 2007.

*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. The Bailey sand exhibits comparable reservoir characteristics to our West Mississippi floods and we expect the Bailey tertiary flood to perform in a similar manner. We elected to co-develop the Bailey sand and Rodessa sand to accelerate the development of the potential tertiary oil reserves at Soso. Although we began initial development of the Bailey sand very late in 2005, the majority of our capital investment to date occurred in 2006, which involved the construction of $CO_2$ facilities and the establishment of the two tertiary injection projects. 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, although injections in the Bailey formation were initially limited because of delays in getting the well work done and limited $CO_2$ supplies. We expect to see our first tertiary production in Soso Field during the second quarter of 2007.

*Tinsley Field.* Tinsley field was acquired in January 2006 and is one of the largest oil fields in the state of Mississippi. As is the case with the majority of fields in Mississippi, Tinsley produces from multiple reservoirs. While we are working the other reservoirs in an attempt to increase current conventional production and reserves, our primary target in Tinsley for $CO_2$ enhanced oil recovery operations is the Woodruff formation. One of the prior operators performed a pilot $CO_2$ project at Tinsley in the Perry sandstone. The $CO_2$ was successful at mobilizing oil but the operator decided not to expand the flood due to low oil prices. The acquisition of the field included an 8" pipeline that was installed to deliver $CO_2$ to the pilot project but was converted to natural gas service some time ago. We have reconditioned the pipeline for $CO_2$ service and initiated limited $CO_2$ injection in Tinsley Field in January 2007. In order to expand our injection of $CO_2$ to the entire field, it will be necessary to install a new $CO_2$ pipeline, which we expect will be completed by the third or fourth quarter of 2007.

*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 revenue, as defined. Delhi is also a future potential $CO_2$ tertiary oil flood candidate that will require construction of a $CO_2$ pipeline before flooding can commence, with current plans to make such a line an extension of the larger, new $CO_2$ pipeline currently planned from Jackson Dome to Tinsley Field. Our goal is to have this $CO_2$ pipeline installed by 2008, with initial oil production from tertiary operations currently anticipated during 2009. As of December 31, 2006, there was not any significant oil production or proved oil reserves at Delhi Field.

*Hastings Field.* During November 2006, we entered into an agreement with a subsidiary of Venoco, Inc. that gives us an option, between November 1, 2008 and November 1, 2009, to purchase their interest in Hastings Field, a strategically significant potential tertiary flood candidate located near Houston, Texas. The agreement provides for the parties to agree upon a purchase price for the conventional proved reserves at the time of the exercise of the option, which may be paid in cash or through a volumetric production payment; failing agreement as to price, the price will be determined by a pre-designated independent petroleum engineering firm using specified criteria for calculation of the discounted present value of proved reserves at that time. As consideration for the option agreement, we made an upfront payment of $37.5 million and are required to make additional payments totaling $12.5 million over the next 20 months. We can extend the option period beyond November 2009 for up to seven additional years at an incremental cost of $30 million per year. None of the option payment amounts will be credited against the purchase price if we exercise the option. If we exercise the option, we will be committed to make aggregate net capital expenditures in the field of approximately $175 million over the subsequent five years to develop the field for tertiary operations, with an obligation to commence $CO_2$ injections in the field within three years following the option exercise. Hastings Field is currently producing approximately 2,400 Bbls/d, although we currently have no economic interest in this production.

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, more reserve potential than any other single field in our inventory. We plan to build a pipeline to transport $CO_2$ to this field (see "$CO_2$ pipelines" above). Based on preliminary 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 $CO_2$ pipeline.

The Hasting Field agreement provides for a significant strategic addition, giving us an anchor field to the Texas Gulf Coast region. The field and the $CO_2$ pipeline will significantly expand our area of operations and growth opportunities into the Texas Gulf Coast region. Denbury continues to evaluate fields in the area to add to a reserve base in the Texas Gulf Coast area.

*Overall Tertiary Economics to Date.* Through December 31, 2006, we spent a total of $665.4 million on tertiary oil fields (including the allocated acquisition costs), and received $472.2 million in net positive cash flow (revenue less operating expenses), or net unrecovered cash flow of $193.2 million, the deficit primarily due to the significant funds expended on acquisitions during 2006. Of our total spending, approximately $273.5 million was spent on fields that had little or no proved reserves at December 31, 2006 (i.e. significant incremental proved reserves are anticipated during 2007 and beyond). 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 $198.7 million as of December 31, 2006, including $54.6 million associated with the Free State $CO_2$ pipeline. At year-end 2006, the proved oil reserves in our tertiary recovery oil fields had a PV-10 Value of $1.46 billion, using December 31, 2006, NYMEX pricing of $61.05 per barrel. In addition, there is significant probable and potential reserves at several other fields for which tertiary operations are underway or planned.

**Texas and the Barnett Shale**

We currently own approximately 74,700 gross acres and 53,800 net acres of leases in the Barnett Shale area in North Central Texas, of which approximately 22,100 gross acres and 19,600 net acres are in the more tested northern areas of Parker and Wise Counties, with the remainder in Erath and adjoining more southern and untested counties. We acquired our initial acreage in this area in 2001 and did only limited development until 2005. Through December 31, 2006, we have spent a total of $267.2 million on the Barnett Shale area and have received $90.1 million in net operating income (revenue less operating expenses), or net negative cash flow of $177.1 million. At December 31, 2006, we had approximately 252.4 Bcfe of proved reserves in the Barnett Shale area with a PV-10 Value of approximately $243.5 million, using December 31, 2006, Henry Hub indicative cash pricing of $5.63 per MMBtu.

We continue to refine our completion and fracturing techniques, including an analysis of the best number of fracture treatments to adequately stimulate the entire length of the lateral sections of our horizontal wells, which can exceed 4,000 feet. During 2006, we drilled an additional 46 horizontal wells, increasing our net Barnett Shale production from approximately 18.3 MMcfe/d in the fourth quarter of 2005 to approximately 35.4 MMcfe/d during the fourth quarter of 2006. During 2006, we finalized the acquisition and interpretation of our 3-D seismic data over our entire northern acreage position, 90 to 100 square miles, and initiated a 3-D shoot of the southern acreage. The 3-D seismic data helps us better locate our wells so that we encounter less faulting and underground sink holes, which have been associated with fracture stimulations into zones outside of the Barnett Shale that are typically water bearing. We expect production in this area to grow significantly during 2007 as we plan to drill approximately 35 to 40 horizontal wells, all of which are scheduled for Parker County. Including seismic costs and pipeline infrastructure costs, our planned 2007 capital expenditures in the Barnett Shale area are estimated to make up $122 million of our current $650 million capital budget.

At this time we are still evaluating the 2006 drilling and completion work in our southern acreage, primarily Erath County. The initial results do not look very encouraging as we drilled five wells, completing three, none of which have been economic. We elected not to complete the last two wells pending a re-analysis of all of our results to date.

**East Mississippi Fields Without Proven 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. For years, this has been our area with the highest production and most proved reserves, representing production of approximately 12,808 BOE/d during the fourth quarter of 2006 (35% of our Company total) and proved reserves of 52.7 MMBOE as of December 31, 2006 (30% 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 three currently have tertiary operations (Soso, Martinville and Eucutta Fields). Production from our East Mississippi fields has been relatively consistent over the last three years, averaging 13,085 BOE/d in 2004, 12,072 BOE/d in 2005 and 12,743 BOE/d during 2006. For 2007, we expect our budget in this region for conventional operations to be around $50 million, about the same as in 2006, representing approximately 8% of our current 2006 exploration and development budget of $650 million.

*Heidelberg Field.* The largest field in the region and one of our largest fields corporately is Heidelberg Field, which for the fourth quarter of 2006 produced an average of 7,444 BOE/d, 2% more than the 2005 average of 7,312 BOE/d. 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. There are 11 producing formations in Heidelberg Field containing 40 individual reservoirs, with the majority of the past and current production coming from the Eutaw, Selma Chalk and Christmas sands at depths of 3,500 to 5,000 feet. When we acquired the property in 1997, production was approximately 2,800 BOE/d.

The majority of the oil production at Heidelberg is from six waterflood units that produce from the Eutaw formation (at approximately 4,400 feet). Most of our recent development at Heidelberg has been in the Selma Chalk, a natural gas reservoir at around 3,700 feet, making Heidelberg our second largest gas field. We have steadily developed the Selma Chalk since 2001, drilling from 13 to 20 wells per year, increasing the natural gas production at Heidelberg to a peak quarterly average of 15.8 MMcf/d in the fourth quarter of 2004, averaging 14.3 MMcf/d during 2006. During 2005 we drilled and completed our first horizontal well in the Selma Chalk. The well was drilled in an area of the field where prior vertical wells typically yielded lower than average production rates. The well was completed in two stages and the results were encouraging. During 2006, we drilled 12 Selma Chalk wells, four of which were horizontal wells, and we plan to drill 13 horizontal wells during 2007.

**South Louisiana**

We own interests in the land and marshes of south Louisiana, a region that produces primarily natural gas. Production from this area averaged 39.4 MMcfe/d net to our interest in the fourth quarter of 2006, a slight increase from our 2005 average of 37.0 MMcfe/d. Production was as high as 51.7 MMcfe/d during the second quarter of 2006 following the completion of several new wells drilled in late 2005 and early 2006, but has declined significantly from that peak as a result of the relatively rapid depletion for wells in this area. During 2006, we spent approximately $64.7 million (excluding acquisitions) in this region, approximately 13% of our total exploration and development expenditures, drilling approximately 12 wells, primarily in Cameron, Jefferson Davis, and Terrebonne Parish areas. For 2007, our spending is expected to be approximately $40 million or 6% of our currently planned $650 million exploration and development budget, significantly less than our 2006 expenditures in this area.

The majority of our onshore Louisiana fields lie in the Houma embayment area of Terrebonne Parish, including Lirette and South Chauvin Fields, and our recent shallow natural gas plays at Bayou Sauveur and Gibson Fields. We drilled four wells in Terrebonne Parish during 2006. In 2007, we plan to drill approximately three exploratory wells in Terrebonne Parish and four development wells.

In late 2005 we spudded our Gumbo Prospect in Terrebonne Parish, the Westerfelt #2 well, a 19,000+ foot well testing the Rob L sands. We logged the well in January 2006, constructed production facilities and completed the well. The well produced approximately 645 MMcf and 26 MBbls of condensate (gross) during a two month period. In October 2006 the well logged-off and is presently being evaluated for sidetracking to another fault block. Based on the Westerfelt #2 production information and pressures, we believe that the Westerfelt #2 encountered an isolated reservoir area that is not in communication with the large feature it was intended to test. Based upon the results of the Westerfelt #2 and review of the seismic interpretation, we decided to drill an offset, the State Lease 18380 #1 well. We believe that this well should encounter a larger reservoir with greater reserve potential. The completion of drilling operations is expected late in the first quarter or early in the second quarter of 2007. Assuming the well logs are favorable, significant production history will be required to fully evaluate the potential reserves associated with this prospect.

**Field Summaries**

Denbury operates in four primary areas: Louisiana, Eastern Mississippi, Western Mississippi and Texas. Our 16 largest fields (listed below) constitute approximately 93% of our total proved reserves on a BOE basis and on a PV-10 Value basis. Within these 16 fields, we own a weighted average 92% 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 five primary field offices located in Houma, Louisiana, Laurel, Mississippi; McComb, Mississippi; Brandon; Mississippi; and Cleburne, Texas.

| | Proved Reserves as of December 31, 2006 [1] | | | | | 2006 Average Daily Production | | |
|---|---|---|---|---|---|---|---|---|
| | Oil (MBbls) | Natural Gas (MMcf) | MBOEs | BOE % of total | PV-10 Value (000's) | Oil (Bbls/d) | Natural Gas (Mcf/d) | Average Net Revenue Interest |
| MISSISSIPPI – $CO_2$ FLOODS | | | | | | | | |
| Brookhaven | **18,987** | **—** | **18,987** | **10.9%** | **$ 353,406** | **833** | **—** | **82.0%** |
| Mallalieu (East & West) | **13,582** | **—** | **13,582** | **7.8%** | **457,200** | **5,210** | **—** | **76.6%** |
| McComb/Olive | **12,717** | **—** | **12,717** | **7.3%** | **297,449** | **1,177** | **—** | **77.0%** |
| Eucutta | **10,313** | **—** | **10,313** | **5.9%** | **186,229** | **47** | **—** | **83.5%** |
| Little Creek & Lazy Creek | **3,696** | **—** | **3,696** | **2.1%** | **90,592** | **2,739** | **—** | **83.3%** |
| Smithdale and other | **2,872** | **—** | **2,872** | **1.7%** | **71,560** | **64** | **—** | **79.3%** |
| Total Mississippi – $CO_2$ floods | **62,167** | **—** | **62,167** | **35.7%** | **1,456,436** | **10,070** | **—** | **79.9%** |
| OTHER MISSISSIPPI | | | | | | | | |
| Heidelberg (East & West) | **25,943** | **51,512** | **34,528** | **19.8%** | **477,186** | **5,036** | **14,330** | **76.2%** |
| Tinsley | **3,299** | **90** | **3,314** | **1.9%** | **60,391** | **881** | **10** | **81.7%** |
| Eucutta | **2,708** | **—** | **2,708** | **1.6%** | **35,524** | **819** | **40** | **69.4%** |
| S. Cypress Creek | **1,903** | **102** | **1,920** | **1.1%** | **26,041** | **233** | **41** | **83.0%** |
| Summerland | **1,662** | **—** | **1,662** | **0.9%** | **20,556** | **445** | **—** | **74.4%** |
| King Bee | **1,458** | **—** | **1,458** | **0.8%** | **17,316** | **269** | **—** | **78.9%** |
| Other Mississippi | **5,172** | **11,694** | **7,121** | **4.1%** | **118,821** | **1,887** | **4,618** | **33.1%** |
| Total Other Mississippi | **42,145** | **63,398** | **52,711** | **30.2%** | **755,835** | **9,570** | **19,039** | **64.9%** |
| LOUISIANA | | | | | | | | |
| S. Chauvin | **436** | **13,940** | **2,759** | **1.6%** | **57,189** | **298** | **11,744** | **38.3%** |
| Thornwell | **406** | **5,876** | **1,385** | **0.8%** | **33,905** | **1,068** | **11,147** | **37.4%** |
| Other Louisiana | **901** | **20,076** | **4,248** | **2.4%** | **75,305** | **789** | **11,800** | **41.0%** |
| Total Louisiana | **1,743** | **39,892** | **8,392** | **4.8%** | **166,399** | **2,155** | **34,691** | **39.5%** |
| TEXAS | | | | | | | | |
| Newark (Barnett Shale) | **11,606** | **182,812** | **42,075** | **24.1%** | **243,474** | **106** | **28,525** | **75.0%** |
| Other Texas | **179** | **669** | **290** | **0.2%** | **1,552** | **8** | **—** | **79.9%** |
| Total Texas | **11,785** | **183,481** | **42,365** | **24.3%** | **245,026** | **114** | **28,525** | **75.1%** |
| ALABAMA | | | | | | | | |
| Citronelle | **8,283** | **—** | **8,283** | **4.8%** | **67,594** | **1,026** | **—** | **62.7%** |
| Other Alabama | **7** | **1,978** | **337** | **0.2%** | **3,165** | **1** | **727** | **30.5%** |
| Total Alabama | **8,290** | **1,978** | **8,620** | **5.0%** | **70,759** | **1,027** | **727** | **60.2%** |
| OTHER | **55** | **77** | **67** | **0.0%** | **744** | **—** | **93** | **0.1%** |
| COMPANY TOTAL | **126,185** | **288,826** | **174,322** | **100.0%** | **$2,695,199** | **22,936** | **83,075** | **57.2%** |

*(1) The reserves were prepared using constant prices and costs in accordance with the guidelines of the SEC based on the prices received on a field-by-field basis as of December 31, 2006. The prices at that date were a NYMEX oil price of $61.05 per Bbl adjusted to prices received by field and a Henry Hub natural gas price average of $5.63 per MMBtu also adjusted to prices received by field.*

### 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 well or 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, 2006:

| | Developed | | Undeveloped | | Total | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Mississippi | **107,930** | **86,143** | **276,809** | **54,303** | **384,739** | **140,446** |
| Louisiana | **56,393** | **49,126** | **21,517** | **15,002** | **77,910** | **64,128** |
| Texas | **20,256** | **18,119** | **56,454** | **37,487** | **76,710** | **55,606** |
| Alabama | **34,329** | **21,919** | **77,524** | **18,887** | **111,853** | **40,806** |
| Other | **5,429** | **1,503** | **38,710** | **9,687** | **44,139** | **11,190** |
| Total | **224,337** | **176,810** | **471,014** | **135,366** | **695,351** | **312,176** |

Denbury's net undeveloped acreage that is subject to expiration over the next three years, if not renewed, is approximately 7% in 2007, 8% in 2008 and 4% in 2009.

#### Productive Wells

The following table sets forth our gross and net productive oil and natural gas wells at December 31, 2006:

| | Producing Oil Wells | | Producing Natural Gas Wells | | Total | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| OPERATED WELLS: | | | | | | |
| Mississippi | **492** | **474.9** | **176** | **161.8** | **668** | **636.7** |
| Louisiana | **30** | **24.7** | **47** | **39.2** | **77** | **63.9** |
| Texas | **3** | **3.0** | **96** | **94.2** | **99** | **97.2** |
| Alabama | **158** | **124.1** | **35** | **20.4** | **193** | **144.5** |
| Other | **—** | **—** | **—** | **—** | **—** | **—** |
| Total | **683** | **626.7** | **354** | **315.6** | **1,037** | **942.3** |
| NON-OPERATED WELLS: | | | | | | |
| Mississippi | **37** | **3.4** | **17** | **3.9** | **54** | **7.3** |
| Louisiana | **—** | **—** | **17** | **3.7** | **17** | **3.7** |
| Texas | **—** | **—** | **4** | **0.5** | **4** | **0.5** |
| Alabama | **—** | **—** | **10** | **1.5** | **10** | **1.5** |
| Other | **1** | **—** | **—** | **—** | **1** | **—** |
| Total | **38** | **3.4** | **48** | **9.6** | **86** | **13.0** |
| TOTAL WELLS: | | | | | | |
| Mississippi | **529** | **478.3** | **193** | **165.7** | **722** | **644.0** |
| Louisiana | **30** | **24.7** | **64** | **42.9** | **94** | **67.6** |
| Texas | **3** | **3.0** | **100** | **94.7** | **103** | **97.7** |
| Alabama | **158** | **124.1** | **45** | **21.9** | **203** | **146.0** |
| Other | **1** | **—** | **—** | **—** | **1** | **—** |
| Total | **721** | **630.1** | **402** | **325.2** | **1,123** | **955.3** |

### Drilling Activity

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

| | Year Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2006 | | 2005 | | 2004 | |
| | Gross | Net | Gross | Net | Gross | Net |
| EXPLORATORY WELLS:[1] | | | | | | |
| Productive[2] | **10** | **8.5** | 12 | 7.1 | 8 | 5.8 |
| Non-productive[3] | **8** | **6.8** | 1 | 0.6 | 4 | 2.3 |
| DEVELOPMENT WELLS:[1] | | | | | | |
| Productive[2] | **90** | **82.7** | 81 | 74.3 | 68 | 53.8 |
| Non-productive[3][4] | **—** | **—** | — | — | 1 | 0.6 |
| Total | **108** | **98.0** | 94 | 82.0 | 81 | 62.5 |

*(1) An exploratory well is a well drilled either in search of a new, as yet undiscovered oil or gas reservoir or to greatly extend the known limits of a previously discovered reservoir. A developmental 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 2006, 2005 and 2004, an additional 14, 5, and 8 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 Income" included herein.

**Title to Properties**

Customarily in the oil and 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, 2006, we had two purchasers that each accounted for 10% or more of our oil and natural gas revenues: Marathon Ashland Petroleum LLC (28%) and Hunt Crude Oil Supply Co. (18%). For the year ended December 31, 2005, three purchasers each accounted for more than 10% of our total oil and natural gas revenues: Marathon Ashland Petroleum LLC (28%), Hunt Crude Oil Supply Co. (20%) and Sunoco, Inc (13%). For the year ended December 31, 2004, two purchasers each accounted for 10% or more of our oil and natural gas revenues: Hunt Crude Oil Supply Co. (21%) and Genesis Energy, L.P. (14%).

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 as well as the corresponding price received. In Heidelberg Field, one of our larger fields, and our other Eastern Mississippi 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 current $CO_2$ 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, 2006, the discount for our oil production from Heidelberg Field averaged $13.31 per Bbl and for our Eastern Mississippi properties as a whole the discount averaged $12.11 per Bbl relative to NYMEX oil prices. For Mallalieu Field, the largest producer during 2006 of our $CO_2$ properties in Western Mississippi, we averaged a premium of $0.20 per Bbl over NYMEX oil prices, and $0.30 per Bbl over NYMEX prices for our tertiary oil production in Western Mississippi taken as a whole. Our Louisiana properties averaged $13.82 per Bbl below NYMEX prices during 2006, largely because the reported oil sales include a significant amount of natural gas liquids, which typically sell at a lower price than crude oil.

### 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 due to our proximity to Henry Hub and the high Btu content of our natural gas. For the year ended December 31, 2006, we averaged $0.77 above NYMEX prices for our Louisiana natural gas production. However, in the Barnett Shale area in Texas, due primarily to its location, the price we received averaged $0.83 below NYMEX prices. We expect our overall differential to NYMEX prices to gradually increase in the future due to our increasing emphasis in the Barnett Shale area.

## 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 funds, 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 costs 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 the regulation of the size of drilling and spacing units 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 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.

### Natural Gas Gathering Regulations

State regulation of natural gas gathering facilities generally include 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; (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. To date, we have not expended any material amounts to comply with such regulations, and 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 Gas Reserves and Present Value of Estimated Future Net Revenues

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, 2006, 2005 and 2004. The reserve estimates were prepared using constant prices and costs in accordance with the guidelines of the Securities and Exchange Commission (SEC). The prices used in preparation of the reserve estimates were based on the market prices in effect as of December 31 of each year, with the appropriate adjustments (transportation, gravity, basic sediment and water ("BS&W"), purchasers' bonuses, Btu, etc.) applied to each field. The 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 interests in our properties.

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 in West Mississippi and our Heidelberg waterfloods in East Mississippi account for approximately 82% 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.

Our proved undeveloped natural gas reserves associated with our Selma Chalk play at Heidelberg and the Barnett Shale play account for approximately 96% of our proved undeveloped natural gas reserves. The remaining undeveloped natural gas reserves are spread over multiple fields. Our current plans for 2006 include drilling 45 to 55 new wells in these two primary natural gas plays.

| | December 31, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| ESTIMATED PROVED RESERVES: | | | |
| Oil (MBbls) | **126,185** | 106,173 | 101,287 |
| Natural gas (MMcf) | **288,826** | 278,367 | 168,484 |
| Oil equivalent (MBOE) | **174,322** | 152,568 | 129,369 |
| PERCENTAGE OF TOTAL MBOE: | | | |
| Proved producing | **48%** | 40% | 39% |
| Proved non-producing | **17%** | 16% | 16% |
| Proved undeveloped | **35%** | 44% | 45% |
| REPRESENTATIVE OIL AND GAS PRICES:(1) | | | |
| Oil – NYMEX | **$ 61.05** | $ 61.04 | $ 43.45 |
| Natural gas – Henry Hub | **5.63** | 10.08 | 6.18 |
| PRESENT VALUES:(2) | | | |
| Discounted estimated future net cash flow before income taxes ("PV-10 Value") (thousands) | **$2,695,199** | $3,215,478 | $1,643,289 |
| Standardized measure of discounted estimated future net cash flow after income taxes (thousands) | **1,837,341** | 2,084,449 | 1,129,196 |

*(1) The prices of each year-end were based on market prices in effect as of December 31 of each year, NYMEX prices per Bbl and Henry Hub cash prices per MMBtu, with the appropriate adjustments (transportation, gravity, BS&W, purchasers' bonuses, Btu, etc.) applied to each field to arrive at the appropriate corporate net price.*

*(2) Determined based on year-end unescalated prices and costs in accordance with the guidelines of the SEC, discounted at 10% per annum.*

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 "Risk Factors – Estimating our reserves, production and future net cash flow is difficult to do with any certainty." See also Note 12, "Supplemental Oil and Natural Gas Disclosures," to the Consolidated Financial Statements.

## Item 1A. Risk Factors

### Risks Related To Our Business

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

Our current long-term growth strategy is focused on our $CO_2$ tertiary recovery operations, and we expect approximately 60% of our 2007 capital expenditures to be in this area. 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 and results of operations and cash flows.

**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 and likely will continue to be volatile in the future, especially given current world geopolitical conditions. 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 72% of our December 31, 2006 proved reserves are oil, with oil being an even larger percentage of our future potential reserves and projects due to our focus on tertiary operations. The prices for oil and natural gas are subject to a variety of additional factors that are beyond our control. These factors include:

- the 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 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 with any certainty. 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 2006, NYMEX oil prices were high throughout the year, averaging $66.27 per Bbl. During 2004, 2005 and 2006, the price we received for our heavier, sour crude oil did not correlate as well with NYMEX prices as it has historically. During 2002 and 2003, our average discount to NYMEX was $3.73 per Bbl and $3.60 per Bbl respectively. During 2004, this differential increased to $4.91 per Bbl for the year as a result of the price deterioration for heavier, sour crudes, and was even higher during 2005, averaging $6.33 per Bbl. Our 2006 differential was about the same as 2005, averaging $6.41 per Bbl. While we attempt to obtain the best price for our crude in our marketing efforts, we cannot control these market price swings and are subject to the market volatility for this type of oil. These price differentials relative to NYMEX prices can significantly impact our profitability.

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, have generally trended upward since that time, although with significant fluctuations along the way. During 2004 NYMEX natural gas prices averaged $6.23 per MMBtu, during 2005 NYMEX averaged $8.97 per MMBtu and during 2006, averaged $6.97 per MMBtu.

**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.

**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. Due to the recent record high oil and gas prices, we have experienced shortages of drilling rigs and other equipment, as demand for rigs and equipment has increased along with the number of wells being drilled. 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.

**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 drilling and acquisitions. 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, often one to two 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 drilling activities are subject to numerous risks, including the risk that no commercially productive oil or natural gas reserves will be encountered. Exploratory drilling involves more risk than development drilling because exploratory drilling is designed to test formations for which proved reserves have not been discovered.

In January 2006, we purchased three oil fields for $250 million that we believe have significant potential oil reserves that can be recovered through the use of tertiary flooding: Tinsley Field approximately 40 miles northwest of Jackson, Mississippi; Citronelle Field in Southwest Alabama, and the smaller South Cypress Creek Field near our Eucutta Field in Eastern Mississippi. These three fields produced approximately 2,569 BOE/d net to the acquired interests during the fourth quarter of 2006, and have proved reserves of approximately 13.5 million BOEs. We purchased these fields 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 to this specific acquisition, we have, and 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.

**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, 2006, two purchasers each accounted for more than 10% of our oil and natural gas revenues and in the aggregate, for 46% 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 flow is difficult to do with any certainty.**

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

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 affect on our financial condition, operating results and cash flows.

The reserve data included in documents incorporated by reference represent only estimates. In accordance with requirements of the SEC, the estimates of present values are based on prices and costs as of the date of the estimates. 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, 2006, approximately 35% 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.

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

As of February 28, 2007, we had approximately $150 million outstanding on our bank credit line with approximately $350 million available on our borrowing base. The next semi-annual redetermination of the borrowing base for our bank credit facility will be on April 1, 2007. 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 in connection with our acquisition, development, exploitation and exploration of oil and natural gas producing properties. Further, our cash flow from operations is highly dependent on the prices that we receive for oil and natural gas. If oil and natural gas prices were to decline significantly, particularly 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;
- 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 increase, 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.

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 bank credit facility, we would be in default. This default would permit the holders of such indebtedness to accelerate the maturity of such indebtedness and could cause defaults under other indebtedness, including the subordinated notes, 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 and to financial, business and other factors, including factors beyond our control.

## Item 1B. Unresolved Staff Comments

None.

## Item 2. Properties

See Item 1. Business – Oil and Gas Operations. We also have various operating leases for rental of office space, office and field equipment, and vehicles. See "Off-Balance Sheet Agreements – Commitments and Obligations" in Management's Discussion and Analysis of Financial Condition and Results of Operations, and Note 11, "Commitments and Contingencies," to the Consolidated Financial Statements for the future minimum rental payments. Such information is incorporated herein by reference.

## Item 3. Legal Proceedings

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

No matters were submitted for a vote of security holders during the fourth quarter of 2006.

## 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. The sales prices are adjusted to reflect the 2-for-1 stock split on October 31, 2005. On April 25, 2006, we closed the $125 million sale (net to Denbury) of 3,492,595 shares of common stock in a public offering. As of January 31, 2007, the number of record holders of Denbury's common stock was 821. Management believes, after inquiry, that the number of beneficial owners of Denbury's common stock is in excess of 10,500. On January 31, 2007, the last reported sales price of Denbury's Common Stock, as reported on the NYSE, was $27.70 per share.

| | 2006 | | 2005 | |
|---|---|---|---|---|
| | High | Low | High | Low |
| First Quarter | **$32.65** | **$ 23.57** | $ 18.32 | $ 12.37 |
| Second Quarter | **36.60** | **25.91** | 20.53 | 14.02 |
| Third Quarter | **35.80** | **26.53** | 25.71 | 19.95 |
| Fourth Quarter | **30.93** | **25.95** | 25.50 | 19.36 |

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. No unregistered securities were sold by the Company during 2006.

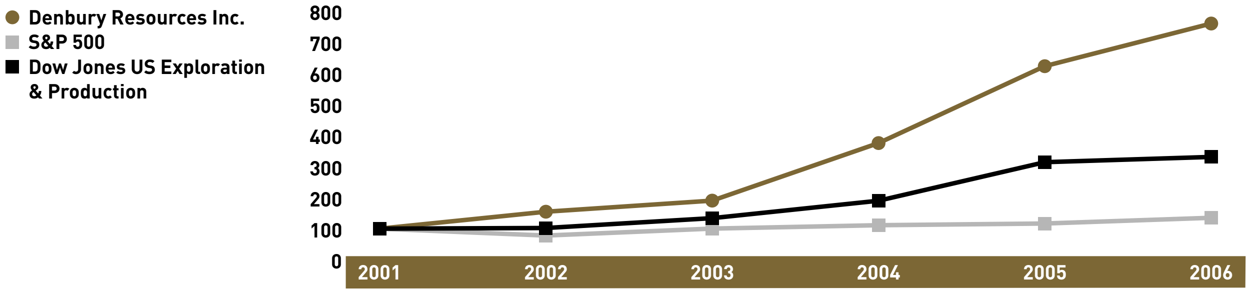
### Share Performance Graph

*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, 2006, 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, 2001, and that dividends were reinvested.

**Cumulative Total Return on $100 Investment**

(December 31, 2001 – December 31, 2006)




| | December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 |
| Denbury | $ 100 | $155 | $190 | $376 | $623 | **$ 760** |
| S&P 500 | 100 | 78 | 100 | 111 | 117 | **135** |
| Dow Jones Exploration and Production | 100 | 102 | 134 | 190 | 314 | **331** |

## Item 6. Selected Financial Data

| (In thousands, unless otherwise noted) | Year Ended December 31, 2006 | 2005 | 2004 [1] | 2003 | 2002 |
|---|---|---|---|---|---|
| CONSOLIDATED STATEMENTS OF OPERATIONS DATA: | | | | | |
| Revenues | **$ 731,536** | $ 560,392 | $ 382,972 | $ 333,014 | $ 285,152 |
| Net income | **202,457 [2]** | 166,471 | 82,448 | 56,553 [3] | 46,795 |
| Net income per common share [4]: | | | | | |
| Basic | **1.74 [2]** | 1.49 | 0.75 | 0.52 [3] | 0.44 |
| Diluted | **1.64 [2]** | 1.39 | 0.72 | 0.51 [3] | 0.43 |
| Weighted average number of common shares outstanding [4]: | | | | | |
| Basic | **116,550** | 111,743 | 109,741 | 107,763 | 106,487 |
| Diluted | **123,774** | 119,634 | 114,603 | 110,928 | 108,730 |
| CONSOLIDATED STATEMENTS OF CASH FLOW DATA: | | | | | |
| Cash provided by (used by): | | | | | |
| Operating activities | **$ 461,810** | $ 360,960 | $ 168,652 | $ 197,615 | $ 159,600 |
| Investing activities | **(856,627)** | (383,687) | (93,550) | (135,878) | (171,161) |
| Financing activities | **283,601** | 154,777 | (66,251) | (61,489) | 12,005 |
| PRODUCTION (DAILY): | | | | | |
| Oil (Bbls) | **22,936** | 20,013 | 19,247 | 18,894 | 18,833 |
| Natural gas (Mcf) | **83,075** | 58,696 | 82,224 | 94,858 | 100,443 |
| BOE (6:1) | **36,782** | 29,795 | 32,951 | 34,704 | 35,573 |
| UNIT SALES PRICE (EXCLUDING HEDGES): | | | | | |
| Oil (per Bbl) | **$ 59.87** | $ 50.30 | $ 36.46 | $ 27.47 | $ 22.36 |
| Natural gas (per Mcf) | **7.10** | 8.48 | 6.24 | 5.66 | 3.31 |
| UNIT SALES PRICE (INCLUDING HEDGES): | | | | | |
| Oil (per Bbl) | **$ 59.23** | $ 50.30 | $ 27.36 | $ 24.52 | $ 22.27 |
| Natural gas (per Mcf) | **7.10** | 7.70 | 5.57 | 4.45 | 3.35 |
| COSTS PER BOE: | | | | | |
| Lease operating expenses | **$ 12.46** | $ 9.98 | $ 7.22 | $ 7.06 | $ 5.48 |
| Production taxes and marketing expenses | **2.71** | 2.54 | 1.55 | 1.17 | 0.92 |
| General and administrative | **3.20** | 2.62 | 1.78 | 1.20 | 0.96 |
| Depletion, depreciation, and amortization | **11.11** | 9.09 | 8.09 | 7.48 | 7.26 |
| PROVED RESERVES: | | | | | |
| Oil (MBbls) | **126,185** | 106,173 | 101,287 | 91,266 | 97,203 |
| Natural gas (MMcf) | **288,826** | 278,367 | 168,484 | 221,887 | 200,947 |
| MBOE (6:1) | **174,322** | 152,568 | 129,369 | 128,247 | 130,694 |
| Carbon Dioxide (MMcf) [5] | **5,525,948** | 4,645,702 | 2,664,633 | 1,613,840 | 815,315 |
| CONSOLIDATED BALANCE SHEET DATA: | | | | | |
| Total assets | **$ 2,139,837** | $ 1,505,069 | $ 992,706 | $ 982,621 | $ 895,292 |
| Total long-term liabilities | **833,380** | 617,343 | 368,128 | 434,845 | 432,616 |
| Stockholders' equity [6] | **1,106,059** | 733,662 | 541,672 | 421,202 | 366,797 |

*(1) We sold Denbury Offshore, Inc. in July 2004.*

*(2) Effective January 1, 2006, we adopted Statement of Financial Accounting Standards No. 123(R), "Share Based Payment."*

*(3) In 2003, we recognized a gain of $2.6 million for the cumulative effect adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations." The adoption of SFAS No. 143 increased basic and diluted net income per common share by $0.02. In April 2003, we recorded a pre-tax charge of $17.6 million associated with an early debt retirement.*

*(4) On 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 split.*

*(5) Based on a gross working interests basis and includes reserves dedicated to volumetric production payments of 210.5 Bcf at December 31, 2006, 237.1 Bcf at December 31, 2005, 178.7 Bcf at December 31, 2004 and 162.6 Bcf at December 31, 2003 (See Note 14 to the Consolidated Financial Statements).*

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

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

We are a growing independent oil and 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 onshore Louisiana, Alabama, and in the Barnett Shale play near Fort Worth, Texas. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling, and proven engineering extraction processes, including secondary and tertiary recovery operations. Our corporate headquarters are in Plano, Texas (a suburb of Dallas), and we have five primary field offices located in Houma, Louisiana; Laurel, Mississippi; McComb, Mississippi; Brandon, Mississippi; and Cleburne, Texas.

**2006 Overview**

*Operating results.* During 2006, the combination of high commodity prices and record annual production resulted in record annual earnings and cash flow from operations. Production for 2006 averaged 36,782 BOE/d, 23% higher than our average production during 2005, with production increases in every operating area. Commodity prices, on a BOE basis net to us, increased 6% between the fiscal year-end 2005 and 2006. Virtually all expenses increased during 2006, on both an absolute and per BOE basis, as we experienced cost increases in almost every aspect of our business. Overall industry costs continue to increase, the primary reason for higher operating costs and depreciation and depletion rates per BOE in 2006. Operating expenses were also impacted by higher energy costs (electrical and fuel charges) and our continuing emphasis on tertiary operations. General and administrative expenses increased 51% between 2005 and 2006 primarily as a result of the adoption of SFAS No. 123(R) relating to stock compensation and continued growth in personnel and inflation in the industry. Interest expense increased 31% as a result of average debt levels that were 83% higher than in 2005, partially offset by $11.3 million of capitalized interest expense, primarily relating to the unevaluated properties included in our 2006 acquisitions. Our commodity derivative contract mark-to-market adjustments were the only positive trend in expenses during 2006, wherein we recognized a $19.8 million gain in 2006, as compared to a $29.0 million loss in 2005. Our derivative gain was primarily a result of our decision to enter into natural gas swaps in mid December 2006 covering between 80% and 90% of our forecasted 2007 natural gas production, followed by a decline in natural gas prices by year-end.

As has been our practice for several years, we are reinvesting virtually all of our cash flow in new projects, with a desire to further increase our production and reserves. During 2006, our proved reserves increased from 152.6 MMBOE as of December 31, 2005 to 174.3 MMBOE as of December 31, 2006, replacing approximately 260% of our 2006 production, over 60% of which was from internal organic growth, with the balance from acquisitions. The most significant reserve additions during 2006 were in the Barnett Shale. We did not recognize many tertiary oil reserve additions during 2006 because of delays in getting projects completed (and the related delays in associated production response) and because of a transition in how proved tertiary oil reserves were being recognized (see "Results of Operations – Depletion, Depreciation and Amortization" for a review of our reserve changes during 2006 and a discussion of our proved tertiary reserves).

Net income for 2006 was $202.5 million as compared to $166.5 million for 2005 and $82.4 million for 2004. The incremental net income during the 2006 was attributable to most of the factors noted above, principally higher production, partially offset by higher costs. Continued high commodity prices during 2006 also played a significant role in the 2006 results.

In addition to inflationary costs in our industry, we are experiencing more and more delays in obtaining goods and services. This industry trend has caused us to experience higher costs than originally forecasted and to periodically fall behind schedule with regard to the timing of planned activities. While there are preliminary signs that these trends are slowing as a result of the decline in commodity prices in late 2006, unless commodity prices remain flat or continue to decrease, we believe that we are likely to see a resumption of these trends. These rising costs, both for operating expenses and capital expenditures, and shortages of goods and services, contribute to delays in completing our planned projects and may cause delays and shortfalls in achieving our anticipated production and profitability targets. See "Results of Operations" for a more thorough discussion of our operating results.

*Continued expansion of our tertiary operations.* Since we acquired our first carbon dioxide tertiary flood in Mississippi in 1999, we have gradually increased our emphasis on these types of operations. We particularly like this play because of its risk profile, rate of return and lack of competition in our operating area. Generally, from East Texas to Florida, there are no known significant natural sources of carbon dioxide except our own, and these large volumes of $CO_2$ that we own drive the play. Please refer to the section entitled "$CO_2$ Operations" below for a discussion of these operations, their potential, and the ramifications of our continuing emphasis on these operations.

Having enough $CO_2$ to flood our tertiary oil fields is one of the most important ingredients, if not the key ingredient, to our tertiary operations. During 2006 we increased our proved $CO_2$ reserve quantities by 19%, from 4.6 Tcf as of December 31, 2005, to approximately 5.5 Tcf as of December 31, 2006 (both of these quantities are on a working interest basis – see "$CO_2$ Operations – $CO_2$ Resources" for further information). We are continuing to buy additional oil fields that are tertiary flood candidates (See "2006 Acquisitions" below).

**2006 Acquisitions.**

*Tinsley and Citronelle Fields.* On January 31, 2006, we completed an acquisition of three producing oil properties that are future potential $CO_2$ tertiary oil flood candidates: Tinsley Field approximately 40 miles northwest of Jackson, Mississippi, Citronelle Field in Southwest Alabama, and the smaller South Cypress Creek Field near the Company's Eucutta Field in Eastern Mississippi. In 2006 we began our tertiary development work at Tinsley Field, consisting primarily of planning, land and engineering work, with more extensive development and facility construction planned for 2007. The timing of tertiary development at Citronelle Field is uncertain as we will need to build a 60-to-70 mile extension of our Free State pipeline ($CO_2$ pipeline from Jackson Dome to East Mississippi) before flooding can commence, and South Cypress Creek will probably be flooded following our initial development of our other East Mississippi properties. The adjusted purchase price for these three properties was approximately \$250 million. The acquisition was funded with proceeds of the \$150 million of senior subordinated notes issued in December 2005 and \$100 million of bank financing under the Company's existing credit facility (repaid in April 2006 with proceeds from our equity offering at that time). During the fourth quarter of 2006, these fields produced an average of 2,569 BOE/d, up slightly from the 2,200 BOE/d at the time of acquisition. As of December 31, 2006, these fields had proved reserves of approximately 13.5 million BOEs. We operate all three fields and own the majority of the working interests.

*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 have achieved \$200 million in net operating revenue, as defined. Delhi is also a future potential $CO_2$ tertiary oil flood candidate that will require construction of a $CO_2$ pipeline before flooding can commence, with current plans to make such a line an extension of the larger, new $CO_2$ pipeline currently planned from Jackson Dome to Tinsley Field. Our goal is to have this $CO_2$ line installed by 2008, with initial oil production from tertiary operations currently anticipated during 2009. No significant oil production or proved oil reserves existed at Delhi Field at December 31, 2006.

*Hastings Field.* During November 2006 we entered into an agreement with a subsidiary of Venoco, Inc. that gives us an option, between November 1, 2008 and November 1, 2009, to purchase their interest in Hastings Field, a strategically significant potential tertiary flood candidate located near Houston, Texas. The agreement provides for the parties to agree upon a purchase price for the conventional proved reserves at the time of the exercise of the option, which may be paid in cash or through a volumetric production payment; failing an agreement as to price, the price will be determined by a pre-designated independent petroleum engineering firm using specified criteria for calculation of the discounted present value of proved reserves at that time. As consideration for the option agreement, we made an upfront payment of \$37.5 million and are required to make additional payments totaling \$12.5 million over the next twenty months. We can extend the option period beyond November 2009 for up to seven additional years at an incremental cost of \$30 million per year. None of the option payment amounts will be credited against the purchase price if we exercise the option. If we exercise the option, we will be committed to make aggregate net capital expenditures in the field of approximately \$175 million over the subsequent five years to develop the field for tertiary operations, with an obligation to commence $CO_2$ injections in the field within three years following the option exercise. Hastings Field is currently producing approximately 2,400 Bbls/d, although we currently have no economic interest in this production.

We believe that Hastings Field has significant potential oil reserves from tertiary flooding. We plan to build a pipeline to transport $CO_2$ to this field, estimated at between 280 and 300 miles, from the southern end of our existing $CO_2$ pipeline which terminates near Donaldsonville, Louisiana. Based on very preliminary estimates, this pipeline is expected to cost between $450 million and $650 million, although this cost could vary significantly depending on the ultimate size of the pipeline, its pressure rating, its specific route, and other variables, all of which are unknown at this time. We are initiating studies related to construction of this line, with a goal of having it installed and operational within the next few years. We anticipate initially transporting $CO_2$ to the Hastings Field from our natural $CO_2$ source at Jackson Dome, but ultimately plan to use manufactured (anthropogenic) sources of $CO_2$ for this tertiary operation. See "Results of Operations – $CO_2$ Resources" for a discussion of an agreement we entered into during 2006 to purchase a man-made source of $CO_2$ from a planned petroleum coke gasification project.

*April 2006 Equity Offering.* On April 25, 2006, we closed the $125 million sale (net to Denbury) of 3,492,595 shares of common stock in a public offering. We used the net proceeds from the offering to repay then current borrowings under our bank credit facility, which were $120 million as of that date, principally incurred to partially fund our $250 million acquisition of three properties in January 2006.

**Capital Resources and Liquidity**

Our current 2007 capital budget is $650 million, excluding any potential acquisitions. Approximately 60% of our 2007 budget is expected to be spent on tertiary related operations, approximately 20% in the Barnett Shale area, and less than 10% on exploration projects, with the balance spent on our conventional properties in Mississippi or Louisiana. This capital program includes an estimated $80 million to $100 million for a $CO_2$ pipeline from our $CO_2$ source at Jackson Dome to Tinsley and Delhi Fields, two oil fields acquired during 2006. Based on futures commodity prices as of the end of January 2007, this budget is $200 million to $250 million greater than our anticipated cash flow from operations, a much greater shortfall than we have had in recent years. Currently, we plan to fund the majority of this shortfall by refinancing our two existing $CO_2$ pipelines with Genesis Energy, L.P. ("Genesis") by entering into some type of long-term financing or sale transaction, effectively paying for the cost of the pipeline over an extended period of time and recouping our cash previously spent. We would anticipate a similar financing with Genesis for the new $CO_2$ pipeline from Jackson Dome to Tinsley and Delhi Fields once it is completed, forecasted at this time to be during the first half of 2008. We have discussed with Genesis that any such financings are conditioned upon Genesis achieving certain goals, primarily the acquisition of other economic projects that are not related to Denbury, based upon acquisition by Genesis of $1.50 of non-Denbury-related acquisitions for every $1.00 of financings or sales with Denbury. If Genesis is not successful in acquiring properties from third parties or we cannot reach mutually agreeable terms with Genesis to sell them these $CO_2$ pipeline assets, we would plan to fund the shortfall with conventional debt and could potentially reduce our capital budget later in the year. As of February 16, 2007, we had $150 million of bank debt outstanding on a $500 million borrowing base (see "Revised bank credit agreement" below), leaving us significant incremental borrowing capacity, more than we currently plan or desire to use.

We monitor our capital expenditures on a regular basis, adjusting them up or down depending on commodity prices and the resultant cash flow. Therefore, during the last few years as commodity prices have increased, we have increased our capital budget throughout the year. As a result of the recent cost inflation in our industry, many of our recent budget increases have related to escalating costs rather than additional projects. In this inflationary environment, we often have to either increase our capital budget or consider the elimination of a portion of our planned projects.

We also continue to pursue additional acquisitions of mature oil fields that we believe have potential as future tertiary flood candidates. These possible acquisitions are difficult to forecast and the purchase price can vary widely depending on the levels in the fields of existing production and conventional proved reserves and commodity prices. Any additional acquisitions would be funded, at least temporarily, with bank or other debt, although if significant, the acquisition would likely be ultimately funded with more permanent capital such as subordinated debt and/or additional equity.

*Revised bank credit agreement.* On September 14, 2006, we entered into a Sixth Amended and Restated Credit Agreement with our nine banks, led by JPMorgan Chase Bank, N.A., as administrative agent. The new agreement (i) improved the credit pricing under the agreement, (ii) extended the term of the credit arrangements by two and one-half years to September 14, 2011, (iii) increased the borrowing base from $300 million to $500 million, (iv) increased the maximum facility size from $300 million to $800 million, and (v) made other minor modifications. Under the new agreement, the commitment amount remained at $150 million, an amount increased in December 2006 to

$250 million. The borrowing base represents the amount that can be borrowed from a credit standpoint based on our 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 ($250 million), up to the borrowing base limit ($500 million), although the banks are not obligated to fund any amount in excess of the commitment amount. At December 31, 2006, we had outstanding $375.0 million (principal amount) of 7.5% subordinated notes, approximately $10.0 million of capital lease commitments, $134.0 million of bank debt, and a working capital deficit of approximately $17.1 million.

### Sources and Uses of Capital Resources

During 2006, we spent $507.3 million on oil and natural gas exploration and development, $63.6 million on $CO_2$ exploration and development, and approximately $319.0 million on property acquisitions, for total capital expenditures of approximately $889.9 million. Our oil and natural gas exploration and development expenditures included approximately $245.3 million spent on drilling, $31.6 million spent on geological, geophysical and acreage expenditures and $230.4 million incurred on facilities and recompletion costs. We funded our total capital expenditures with $461.8 million of cash flow from operations, $125 million of equity, $134 million of net bank borrowings, and a $13.2 million increase in our accrued capital expenditures, with the balance funded with working capital, predominately cash from the December 2005 issuance of $150 million of subordinated debt. Adjusted cash flow from operations (a non-GAAP measure defined as cash flow from operations before changes in assets and liabilities as discussed below under "Results of Operations-Operating Results") was $448.4 million for 2006, while cash flow from operations for the same period, the GAAP measure, was $461.8 million.

During 2005, we spent $292.8 million on oil and natural gas exploration and development expenditures, $76.8 million on $CO_2$ exploration and development expenditures (including approximately $46.0 million for our $CO_2$ pipeline to East Mississippi), and approximately $70.9 million on property acquisitions, for total capital expenditures of approximately $440.5 million. Our exploration and development expenditures included approximately $147.8 million spent on drilling, $25.5 million of geological, geophysical and acreage expenditures and $135.1 million spent on facilities and recompletion costs. Our 2005 acquisition expenditures include the purchase of additional interest and acreage in the Barnett Shale area and purchase of two oil fields, Cranfield and Lake St. John Fields, which may be potential tertiary flood candidates in the future. Our $440.5 million of capital expenditures included an increase of $18.2 million in our accrued capital expenditures, with the remaining cash portion of our capital expenditures funded primarily with $361.0 million of cash flow from operations and approximately $57 million of short-term investments remaining at December 31, 2004, from the sale of our offshore properties during 2004. Additionally, we issued $150 million of subordinated debt in December 2005 and raised $14.4 million during 2005 from the sale of another volumetric production payment of $CO_2$ to Genesis, along with a related long-term $CO_2$ supply agreement with an industrial customer. All of these sources not only funded our capital expenditures, but also increased our cash balance at year-end 2005 to $165.1 million, with a portion of such funds used in January 2006 to partially fund our $250 million acquisition. Adjusted cash flow from operations (a non-GAAP measure defined as cash flow from operations before changes in assets and liabilities as discussed below under "Results of Operations – Operating Results" below) was $343.4 million for 2005, while cash flow from operations for the same period, the GAAP measure, was $361.0 million.

During 2004, we spent $167.0 million on oil and natural gas exploration and development expenditures, $42.4 million on $CO_2$ exploration and development expenditures, and approximately $18.9 million on property acquisitions, for total capital expenditures of approximately $228.3 million. Our exploration and development expenditures included approximately $138.9 million spent on drilling, $18.9 million of geological, geophysical and acreage expenditures and $51.6 million spent on facilities and recompletion costs. We funded these expenditures with $168.7 million of cash flow from operations, with the balance funded with net proceeds from the sale of our offshore properties. We paid back all of our bank debt during the third quarter of 2004 with the offshore sale proceeds, leaving us with approximately $33.0 million of cash and $57.2 million of short-term investments as of December 31, 2004. We also raised $4.8 million during the third quarter of 2004 from the sale of another volumetric production payment of $CO_2$ to Genesis, along with a related long-term $CO_2$ supply agreement with an industrial customer. Adjusted cash flow from operations (a non-GAAP measure defined as cash flow from operations before changes in assets and liabilities as discussed below under "Results of Operations-Operating Results") was $200.2 million for 2004, while cash flow from operations, the GAAP measure, was $168.7 million.

## Off-Balance Sheet Arrangements

### Commitments and Obligations

We have no off-balance sheet arrangements, special purpose entities, financing partnerships or guarantees, other than as disclosed in this section. We have no debt or equity triggers based upon our stock or commodity prices. Our dollar denominated payment obligations that are not on our balance sheet include our operating leases, which at year-end 2006 totaled $101.4 million (including $71.4 million of 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. Additionally, we have dollar related 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 "Results of Operations – Depletion, Depreciation and Amortization" below.

At December 31, 2006, we had a total of $10.5 million outstanding in letters of credit. Genesis Energy, Inc., our 100% owned subsidiary that is the general partner of Genesis, may, as general partner, be a potential guarantor of the bank debt of Genesis, which consists of $8.0 million in debt and $4.6 million in letters of credit at December 31, 2006. There were no guarantees by Denbury or any of its other subsidiaries of the debt of Genesis or of Genesis Energy, Inc. at December 31, 2006. We do not have any material transactions with related parties other than sales of production, transportation arrangements, and capital leases with Genesis made in the ordinary course of business, and volumetric production payments of $CO_2$ ("VPP") sold to Genesis as discussed in Note 3 to our Consolidated Financial Statements.

A summary of our obligations at December 31, 2006, is presented in the following table:

| | Payments Due by Period | | | | | | |
|---|---|---|---|---|---|---|---|
| Amounts in Thousands | Total | 2007 | 2008 | 2009 | 2010 | 2011 | Thereafter |
| CONTRACTUAL OBLIGATIONS: | | | | | | | |
| Subordinated debt [a] | **$ 375,000** | **$ —** | **$ —** | **$ —** | **$ —** | **$ —** | **$375,000** |
| Senior Bank Loan [a] | **134,000** | **—** | **—** | **—** | **—** | **134,000** | **—** |
| Estimated interest payments on subordinated debt and Senior Bank Loan [a] | **246,164** | **36,634** | **36,634** | **36,634** | **36,634** | **34,116** | **65,512** |
| Operating lease obligations | **101,378** | **13,056** | **12,667** | **11,857** | **11,527** | **10,967** | **41,304** |
| Capital lease obligations [b] | **10,028** | **1,291** | **1,291** | **1,529** | **1,291** | **1,291** | **3,335** |
| Capital expenditure obligations [c] | **102,660** | **66,386** | **20,284** | **14,235** | **1,755** | **—** | **—** |
| Derivative contracts (receipt) payment [d] | **(14,726)** | **(22,125)** | **7,399** | **—** | **—** | **—** | **—** |
| Hastings field purchase option | **12,500** | **7,500** | **5,000** | **—** | **—** | **—** | **—** |
| OTHER CASH COMMITMENTS: | | | | | | | |
| Future development costs on proved oil and gas reserves, net of capital obligations [e] | **463,707** | **180,000** | **141,523** | **85,490** | **19,367** | **9,442** | **27,885** |
| Future development cost on proved $CO_2$ reserves, net of capital obligations [f] | **149,367** | **31,267** | **20,000** | **—** | **—** | **11,000** | **87,100** |
| Asset retirement obligations [g] | **91,338** | **1,940** | **1,130** | **2,428** | **5,351** | **1,509** | **78,980** |
| Total | **$1,671,416** | **$ 315,949** | **$ 245,928** | **$152,173** | **$ 75,925** | **$ 202,325** | **$ 679,116** |

*(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 future minimum cash commitments of $8.2 million to Genesis under capital leases in place at December 31, 2006, primarily for transportation of crude oil and $CO_2$, $1.6 million for our office in Laurel, Mississippi, and auto leases for $0.2 million. Approximately $3.0 million of these payments represents interest.*

*(c) Represents future minimum cash commitments under contracts in place as of December 31, 2006, primarily for 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 2007 is currently set at $650 million. In addition, we 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.*

*(d) Represents the estimated future payments under our oil and gas derivative contracts based on the futures market prices as of December 31, 2006. 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, 2006, was a $15.7 million net asset. 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 in Note 10 to the Consolidated Financial Statements.*

*(e) Represents projected capital costs as scheduled in our December 31, 2006 proved reserve report that are necessary in order to recover our proved undeveloped oil and natural gas reserves. These are not contractual commitments and are net of any other capital obligations shown under "Contractual Obligations" in table above.*

*(f) Represents projected capital costs as scheduled in our December 31, 2006 proved reserve report that are necessary in order to recover our proved undeveloped $CO_2$ 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.*

*(g) Represents the estimated future asset retirement obligations on an undiscounted basis. The present discounted asset retirement obligation is $41.1 million, as determined under SFAS No. 143, is further discussed in Note 4 to the Consolidated Financial Statements.*

The above table does not include the commitment to purchase $CO_2$ from the proposed Faustina plant, if built (see "Results of Operations – $CO_2$ Resources – Man-made $CO_2$ sources" below) and does not include the commitments related to Hastings Field if the purchase option is exercised by us (see "2006 Acquisitions" above), as both obligations are contingent on certain events. The above table does include the remaining $12.5 million due on the Hastings option payment.

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 ("VPP") entered into during 2003 through 2005. 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 391 Bcf of $CO_2$ to these customers over the next 17 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, currently we project that our commitment would likely be reduced to approximately 255 Bcf. The maximum volume required in any given year is approximately 105 MMcf/d, although based on our current level of deliveries, this would likely be reduced to approximately 69 MMcf/d. Given the size of our proven $CO_2$ reserves at December 31, 2006 (approximately 5.5 Tcf before deducting approximately 210.5 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.* Our interest in tertiary operations has increased to the point that approximately 60% of our 2007 capital budget is dedicated to tertiary related operations. We particularly like this play as (i) it has a lower risk and is more predictable than most traditional exploration and development activities, (ii) it provides a reasonable rate of return at relatively low oil prices (generally around $30 a barrel at today's cost levels, 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 carbon dioxide except our own, and these large volumes of $CO_2$ that we own drive the play.

We talk about our tertiary operations by labeling operating areas or groups of fields as phases. Phase I is in Southwest Mississippi and includes several fields along our 183-mile $CO_2$ pipeline that we acquired in 2001. The most significant fields in this area are Little Creek, Mallalieu, McComb and Brookhaven. Phase II, which began with the early 2006 completion of our $CO_2$ pipeline to East Mississippi, includes

Eucutta, Soso, Martinville and Heidelberg Fields. With the properties acquired in our January 2006 acquisition (see "2006 Acquisitions" above), we have labeled the planned operations at Tinsley Field, Northwest of Jackson Dome, as Phase III. Phase IV includes Cranfield and Lake St. John Fields, two fields near the Mississippi/Louisiana border located west of the Phase I fields, and Phase V is Delhi Field, a Louisiana field we acquired in 2006, located southwest of Tinsley Field (see "2006 Acquisitions"). Ultimately, we also plan to ultimately flood Citronelle Field, another field acquired in 2006, and Hastings Field, a field on which we acquired a purchase option in late 2006. We have not yet labeled these two fields as a specific phase.

*$CO_2$ Resources.* In February 2001, we acquired the $CO_2$ source field located near Jackson, Mississippi, and a 183-mile pipeline to transport it to our oil fields. Since February 2001, we have acquired two producing wells and drilled 11 additional $CO_2$ producing wells, significantly increasing our estimated proved $CO_2$ reserves from approximately 800 Bcf at the time of the 2001 acquisition to approximately 5.5 Tcf as of December 31, 2006, approximately 250 Bcf more than we estimate we need for our existing and currently planned phases of tertiary operations. During 2006, our proven $CO_2$ reserves increased approximately 19%, or 900 Bcf, from 4.6 Tcf to 5.5 Tcf. The estimate of 5.5 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 4.5 Tcf. Both reserve estimates are included in the evaluation of proven $CO_2$ reserves prepared by DeGolyer & 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 both for Denbury's tertiary recovery programs and industrial users, as Denbury is responsible for distributing the entire $CO_2$ production stream for both of these uses. We currently estimate that it will take approximately 850 Bcf of $CO_2$ to develop and produce the proved tertiary recovery reserves we have recorded at December 31, 2006.

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 and Louisiana that could be further exploited through tertiary recovery. As of January 2007, we estimate that we are capable of producing approximately 470 MMcf/d of $CO_2$, over seven 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 2007, in order to further increase our production capacity and potentially increase our proven $CO_2$ reserves. Our drilling activity at Jackson Dome will continue beyond 2007 as our current forecasts for the five phases which are specifically planned to date suggest that we will need approximately 1,000 MMcf/d of $CO_2$ production by 2011.

In addition to using CO2 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 a volumetric production payment for the $CO_2$. Our average daily $CO_2$ production during 2004, 2005 and 2006 was approximately 218 million, 242 million, and 342 million cubic feet per day, of which approximately 73% in 2004, 73% in 2005, and 75% in 2006 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.

We spent approximately $0.19 per Mcf in operating expenses to produce our $CO_2$ during 2006, more than our 2005 average of $0.16 per Mcf, principally as a result of higher oil commodity prices, which results in higher royalty payments, and higher labor, utilities and equipment rental expense. During 2004, we spent approximately $0.12 per Mcf to produce our $CO_2$. Our estimated total cost per thousand cubic feet of $CO_2$ during 2006 was approximately $0.28, after inclusion of depreciation and amortization expense related to the $CO_2$ production, as compared to approximately $0.25 during 2005.

*Man-Made $CO_2$ sources.* We entered into an agreement and committed to purchase (if the plant is built) 100% of the $CO_2$ production from a man-made (anthropogenic) source of $CO_2$, a planned petroleum coke gasification project scheduled to be completed in 2010. This Faustina plant, proposed to be located near Donaldsonville, LA, will convert petroleum coke into ammonia. As a byproduct of the combustion, large quantities of $CO_2$ will be produced, estimated to be around 200 MMcf/d. We plan to use this $CO_2$ in our tertiary operations program to recover oil. The Faustina agreement allows us to add the potential equivalent volume of an additional one Tcf of $CO_2$ over the term of our contract. Construction of this plant has not yet begun, so we are not certain whether this plant will be built, although it currently appears likely. We are in discussions with several other entities that are considering other types of coal or petroleum coke gasification plants. The cost of this man-made $CO_2$ will likely be higher than $CO_2$ from our natural source, but the location of these plants could mitigate some of the incremental cost of transporting $CO_2$ from Jackson Dome. Further, we see these sources as a possible expansion of natural sources, assuming they are economical, and we believe that our potential ability to tie these sources together with pipelines will give us a significant advantage over our competitors in our geographic area in acquiring additional oil fields and in acquiring these future potential man-made sources of $CO_2$.

*Overview of Tertiary Economics.* Initially, our tertiary operations were economic at oil prices below $20 per Bbl, although the economics have always varied by field. Our costs have escalated during the last few years due to general cost inflation in the industry, raising our current economic oil price to around $30 per Bbl, again dependent on the specific field. 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, 2006, are approximately $8.50 per BOE. Currently, we forecast that these costs will range from $5 to $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, etc. Our operating costs for tertiary operations are expected to range from $13 to $15 per BOE over the life of each field (at today's prices), again depending on the field itself, however, our 2006 operating costs were in excess of this range.

Oil quality is another significant factor that impacts the economics. In Phase I (Southwest Mississippi), the light sweet oil produced from our tertiary operations receives near NYMEX prices, while the average discount to NYMEX for the lower quality oil produced from the fields in Phase II (East Mississippi), some of which we started flooding during 2006, was $13.51 per BOE during 2006, a differential that is significantly higher than our corporate historical averages and one that appears to increase as oil prices increase. See "Oil and Natural Gas Revenues" below for a further discussion of our NYMEX differentials.

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 on our financial results and certain operating statistics.

First, there is a significant delay between the initial capital expenditures and operating expenses and the resulting production increases, as we must build facilities 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) to the injection of $CO_2$. Further, we may spend significant amounts of capital before we can recognize any proven reserves from fields we flood (See "Analysis of Tertiary Recovery Operations" below). Even after a field has proven reserves, there will usually be significant amounts of additional capital required to fully develop the field.

Secondly, these tertiary projects are usually more expensive to operate than our 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). As commodity and energy prices increase, so do our operating expenses in these fields. Our operating cost during 2006 for our tertiary operations averaged $17.69 per Bbl for our producing tertiary fields, as compared to an estimated cost of around $12 to $15 per BOE for a more traditional oil property. We allocate the cost to produce and transport the $CO_2$ between $CO_2$ used in our own oil fields and $CO_2$ sold to commercial users (including obligations covered by the volumetric production payments sold to Genesis). Most of our $CO_2$ operating expenses are allocated to our oil fields and recorded as lease operating expenses on those fields at the time the $CO_2$ is injected. Since we expense all of the operating costs to produce and inject our $CO_2$, the operating costs per barrel will be higher at the inception of $CO_2$ injection projects before oil production is realized in a particular field. Our total corporate operating expenses on a per BOE basis will likely continue to increase as these operations constitute an increasingly larger percentage of our operations. Generally, these higher operating costs are somewhat offset by lower finding and development costs which helps to lower our overall depreciation and depletion rate (see also "Overview of Tertiary Economics" above).

Third, our net oil price relative to NYMEX prices may be affected by the oil produced from our tertiary operations (see "Overview of Tertiary Operations" above). Currently, all of our current oil production from tertiary operations is from fields that produce light sweet oil and receive oil prices close to, and sometimes actually higher than, NYMEX prices. However, the oil produced from fields that we recently commenced flooding as part of Phase II generally sell at a significant discount to NYMEX because of the quality of the crude oil there. The relative mix of this production, coupled with changing market conditions for the various types of crude, can cause our NYMEX differentials to fluctuate widely.

*Analysis of $CO_2$ Tertiary Recovery Operating Activities.* We currently have tertiary operations ongoing at Little Creek, Mallalieu, McComb and Brookhaven Fields in Phase I and Soso, Martinville and Eucutta Fields in Phase II, as well as in various smaller adjacent fields. We project that our oil production from these 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, 2006, we had approximately 62.2 MMBbls of proven oil reserves related to tertiary operations (51.7 MMBbls of which was in Phase I and the balance in Phase II) and have identified and estimate significant additional oil potential in other fields that we own in this region. We initiated $CO_2$ injections at Tinsley Field (Phase III) in January 2007, although in very limited amounts, with more significant development expected there when the $CO_2$ pipeline to Tinsley is completed, which we currently anticipate in the third or fourth quarter of 2007. We also expect to initiate flooding at Cranfield and Lockhart Crossing Fields in the second half of 2007 (Phase IV).

With regard to our proven tertiary reserves, 2006 was a transition year for us, as we added only 6.0 MMBbls of tertiary-related proved oil reserves during the year, primarily incremental oil reserves at McComb and Mallalieu Fields (both Phase I). Previously, we booked most proven tertiary oil reserves near the start of a project as almost all the oil fields in Phase I were analogous to Little Creek Field (our first flood) and thus it was not necessary to have an oil production response to the $CO_2$ injections before they were considered proven. Conversely, our new floods (after Phase I) are not analogous (for the most part), as the tertiary floods will be in different geological formations. Therefore for these new phases, there must be an oil production response to the $CO_2$ injections before we can recognize proven oil reserves, even though we believe that these formations have a similar risk profile. Since many of our Phase II projects were delayed during 2006, the production response needed to record any significant incremental tertiary oil reserves in this new area did not take place. We anticipate booking significant amounts of proven tertiary oil reserves during 2007 and beyond, although the magnitude will depend on our progress with Phases III and IV, two areas we plan to initiate during 2007, and the response from our new Phase II projects.

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 10,070 Bbls/d during 2006. Tertiary oil production represented approximately 44% of our total corporate oil production during 2006 and approximately 27% 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. During 2006, our $CO_2$ injections were less than we forecasted due to a series of different types of delays in obtaining equipment or completing facilities, resulting in a corresponding shortfall between our forecasted and actual tertiary oil production. These delays are caused by various factors: difficulties reentering certain injection wells, which has required that some wells be redrilled; delays in getting certain permits and right-of-ways; and a general tightening of available materials and equipment in the industry. This temporary fluctuation in oil production 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. For our tertiary oil production, we anticipate a 40% to 50% increase in our average production rates for 2007 as compared to 2006 levels. A detailed discussion of each of our tertiary oil fields and the development of each is included on pages 7 – 9 under *"Our Tertiary Oil Fields with Proven Tertiary Reserves."* Following is a chart with our tertiary oil production by field for 2004, 2005 and by quarter for 2006.

| Tertiary Oil Field | Average Daily Production (BOE/d) First Quarter 2006 | Second Quarter 2006 | Third Quarter 2006 | Fourth Quarter 2006 | Year Ended December 31, 2006 | 2005 | 2004 |
|---|---|---|---|---|---|---|---|
| Brookhaven | **547** | **798** | **965** | **1,014** | **833** | 31 | — |
| Little Creek & Lazy Creek | **3,006** | **3,056** | **2,623** | **2,279** | **2,739** | 3,529 | 3,148 |
| Mallalieu (East and West) | **5,219** | **5,385** | **5,243** | **4,994** | **5,210** | 4,739 | 3,351 |
| McComb & Olive | **932** | **1,062** | **1,242** | **1,467** | **1,177** | 908 | 285 |
| Smithdale | **54** | **74** | **41** | **63** | **58** | 8 | — |
| Martinville | **—** | **—** | **—** | **24** | **6** | — | — |
| Eucutta | **—** | **—** | **—** | **187** | **47** | — | — |
| Total tertiary oil production | **9,758** | **10,375** | **10,114** | **10,028** | **10,070** | 9,215 | 6,784 |

In addition to higher energy costs to operate our tertiary recycling facilities caused by higher commodity prices, we have experienced general cost inflation during the last few years. We also lease a portion of our recycling and plant equipment used in our tertiary operations, which further increases operating expenses. Over the last four years we have leased certain equipment that qualifies for operating lease treatment representing an underlying aggregate cost of approximately $71.4 million as of December 31, 2006. We expect to enter into new leases for equipment during 2007 and 2008 representing additional underlying costs of approximately $44 million. These leases have been an attractive cost of financing due to their low imputed interest rates, which are fixed for seven to ten years. During 2006, the cost to produce our $CO_2$ also increased (see "$CO_2$ Resources" above), all of which resulted in an increase in our tertiary operating cost per BOE from $12.00 per BOE in 2005 to $17.69 per BOE during 2006. Included in the 2006 amount is approximately $7.5 million, or approximately $2.04 per BOE, for operating expenses at three new tertiary floods in Phase II where we commenced operations but have had only a very limited or no production response to date (initial response is expected late in 2007 and beyond). The absolute amount of operating expenses related to tertiary operations increased from $24.6 million during 2004 to $40.4 million during 2005 to $65.0 million during 2006.

Through December 31, 2006, we spent a total of $665.4 million on fields currently being flooded (including allocated acquisition costs) and received $472.2 million in net cash flow (revenue less operating expenses and capital expenditures). Of this total, approximately $273.5 million was spent on fields which had little or no proved reserves at December 31, 2006 (i.e., significant incremental proved reserves are anticipated during 2007 and beyond). The proved oil reserves in our $CO_2$ fields have a PV-10 Value of $1.46 billion, using December 31, 2006 constant NYMEX pricing of $61.05 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. Through December 31, 2006, we had a balance of approximately $198.7 million of unrecovered net cash flows for our $CO_2$ assets.

*$CO_2$ Related Capital Budget for 2007.* Tentatively, we plan to spend approximately $70 million in 2007 in the Jackson Dome area with the intent to add additional $CO_2$ reserves and deliverability for future operations. Approximately $60 million in capital expenditures is budgeted in 2007 for our Phase II properties (East Mississippi) and approximately $200 million for Phase III properties (Tinsley), plus an additional $70 million for properties in other phases, making our combined $CO_2$ related expenditures just over 60% of our $650 million 2007 capital budget.

### Operating Results

Adjusted cash flow from operations (see discussion below regarding this non-GAAP measure) and net income have increased each year during the last three years, along with rising commodity prices. Production declined 10% from 2004 to 2005, primarily related to the sale of our offshore properties in July 2004 and to a lesser extent due to the hurricanes during 2005, but the effect of this deferred production was more than offset by higher commodity prices in 2005. Production increased 23% between 2005 and 2006, which, coupled with high prices, resulted in record annual net income and cash flow. Included in our 2006 net income is the effect of approximately $7.5 million of non-cash charges related to the adoption of SFAS No. 123(R) as of January 1, 2006, relating to certain stock-based compensation that was previously only reflected as a footnote disclosure and not recorded in the financial statements (See Note 9 to the Consolidated Financial Statements) and approximately $6.0 million of other non-cash stock charges associated with the departure of a senior vice president and retirement of another vice president, both during 2006.

| | Year Ended December 31, | | |
|---|---|---|---|
| Amounts in Thousands Except Per Share Amounts | 2006 | 2005 | 2004 |
| Net income | **$202,457** | $166,471 | $ 82,448 |
| Net income per common share: | | | |
| Basic | **$ 1.74** | $ 1.49 | $ 0.75 |
| Diluted | **1.64** | 1.39 | 0.72 |
| Adjusted cash flow from operations | **$448,414** | $343,383 | $200,193 |
| Net change in assets and liabilities relating to operations | **13,396** | 17,577 | (31,541) |
| Cash flow from operations (GAAP measure) | **$461,810** | $360,960 | $168,652 |

Adjusted cash flow from operations is a non-GAAP measure that represents cash flow provided by operations before changes in assets and liabilities, as calculated from our Consolidated Statements of Cash Flows. Cash flow from operations is the GAAP measure as presented in our Consolidated Statements of Cash Flows. In our discussion herein, we have elected to discuss these two components of cash flow provided by operations.

Adjusted cash flow from operations, the non-GAAP measure, measures the cash flow earned or incurred from operating activities without regard to the collection or payment of associated receivables or payables. We believe that it is important to consider adjusted cash flow from operations separately, as we believe it can often be a better way to discuss changes in operating trends in our business caused by changes in production, prices, operating costs, and related operational factors, without regard to whether the earned or incurred item was collected or paid during that year. We also use this measure because the collection of our receivables or payment of our obligations has not been a significant issue for our business, but merely a timing issue from one period to the next, with fluctuations generally caused by significant changes in commodity prices or significant changes in drilling activity.

The net change in assets and liabilities relating to operations is also important as it does require or provide additional cash for use in our business; however, we prefer to discuss its effect separately. For instance, during 2004, we had a $31.5 million difference between our adjusted cash flow from operations and our GAAP cash flow from operations. The most significant factor was the transfer of approximately $12.5 million of accrued production receivables relating to our offshore properties that existed as of the closing date to the offshore property purchaser. This reduction in accrued production receivables during 2004 was not considered a collection of receivables for our GAAP cash flow from operations. In addition to the effect of transferred receivables, our other accrued production receivables increased during the year due to the increase in commodity prices, and we reduced our accounts payable and accrued liabilities by approximately $10.5 million as a result of less overall activity as of year-end. During 2005, we had a $17.6 million increase to our GAAP cash flow from operations resulting from the net change in assets and liabilities relating to operations. This is primarily due to higher accounts payable and accrued liabilities associated with increased capital spending levels as compared to the prior year. Our accrual for production receivables was higher at the end of 2006 than a year earlier, due to higher oil and natural gas prices, partially offsetting the benefit of higher accounts payable and accrued liabilities. During 2006, we also had a $13.4 million increase to our GAAP cash flow from operations resulting from the same items as in 2005; namely higher accounts payable and accrued liabilities due to the higher spending levels, partially offset by an increase in our accrued production receivable as a result of the higher production levels in 2006.

Certain of our operating statistics for each of the last three years are set forth in the following chart:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| AVERAGE DAILY PRODUCTION VOLUMES | | | |
| Bbls/d | **22,936** | 20,013 | 19,247 |
| Mcf/d | **83,075** | 58,696 | 82,224 |
| BOE/d [1] | **36,782** | 29,795 | 32,951 |
| OPERATING REVENUES (IN THOUSANDS) | | | |
| Oil sales | **$ 501,176** | $ 367,414 | $256,843 |
| Natural gas sales | **215,381** | 181,641 | 187,934 |
| Total oil and natural gas sales | **$716,557** | $549,055 | $444,777 |
| OIL AND GAS DERIVATIVE CONTRACTS (IN THOUSANDS) [2] | | | |
| Cash expense on settlements of derivative contracts | **$ (5,302)** | $ (16,761) | $(84,557) |
| Non-cash derivative (expense) income | **25,130** | (12,201) | (1,270) |
| Total income (expense) from oil and gas derivative contracts | **$ 19,828** | $ (28,962) | $(85,827) |
| OPERATING EXPENSES (IN THOUSANDS) | | | |
| Lease operating expenses | **$ 167,271** | $108,550 | $ 87,107 |
| Production taxes and marketing expenses [3] | **36,351** | 27,582 | 18,737 |
| Total production expenses | **$203,622** | $ 136,132 | $105,844 |
| NON-TERTIARY $CO_2$ OPERATING MARGIN (IN THOUSANDS) | | | |
| $CO_2$ sales and transportation fees [4] | **$ 9,376** | $ 8,119 | $ 6,276 |
| $CO_2$ operating expenses | **3,190** | 2,251 | 1,338 |
| Non-tertiary $CO_2$ operating margin | **$ 6,186** | $ 5,868 | $ 4,938 |
| UNIT PRICES–INCLUDING IMPACT OF DERIVATIVE SETTLEMENTS [2] | | | |
| Oil price per Bbl | **$ 59.23** | $ 50.30 | $ 27.36 |
| Gas price per Mcf | **7.10** | 7.70 | 5.57 |
| UNIT PRICES–EXCLUDING IMPACT OF DERIVATIVE SETTLEMENTS [2] | | | |
| Oil price per Bbl | **$ 59.87** | $ 50.30 | $ 36.46 |
| Gas price per Mcf | **7.10** | 8.48 | 6.24 |
| OIL AND GAS OPERATING REVENUES AND EXPENSES PER BOE [1] | | | |
| Oil and natural gas revenues | **$ 53.37** | $ 50.49 | $ 36.88 |
| Oil and gas lease operating expenses | **$ 12.46** | $ 9.98 | $ 7.22 |
| Oil and gas production taxes and marketing expenses | **2.71** | 2.54 | 1.55 |
| Total oil and natural gas production expenses | **$ 15.17** | $ 12.52 | $ 8.77 |

*(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. Effective January 1, 2005, we elected to discontinue hedge accounting for our oil and natural gas derivative contracts; see Note 10 to the Consolidated Financial Statements and "Critical Accounting Policies and Estimates – Oil and Gas Derivative Contracts" below.*

*(3) For 2006, 2005 and 2004, includes transportation expenses paid to Genesis of $4.4 million, $4.0 million and $1.2 million, respectively.*

*(4) For 2006, 2005, and 2004 includes deferred revenue of $4.2 million, $3.1 million and $2.4 million respectively, associated with volumetric production payments and transportation income of $4.6 million, $3.5 million and $2.7 million, respectively, both from Genesis.*

*Production.* Average daily production by area for 2006, 2005 and 2004, and each of the quarters of 2006 is listed in the following table (BOE/d).

| | Average Daily Production (BOE/d) | | | | | | |
|---|---|---|---|---|---|---|---|
| | First Quarter | Second Quarter | Third Quarter | Fourth Quarter | Year Ended December 31, | | |
| Operating Area | 2006 | 2006 | 2006 | 2006 | 2006 | 2005 | 2004 |
| Mississippi – non-$CO_2$ floods | **12,455** | **12,633** | **13,069** | **12,808** | **12,743** | 12,072 | 13,085 |
| Mississippi – $CO_2$ floods | **9,758** | **10,375** | **10,114** | **10,028** | **10,070** | 9,215 | 6,784 |
| Onshore Louisiana | **8,349** | **8,623** | **8,221** | **6,572** | **7,937** | 6,164 | 7,630 |
| Barnett Shale | **3,953** | **4,621** | **4,952** | **5,925** | **4,868** | 2,145 | 587 |
| Alabama | **917** | **1,213** | **1,215** | **1,243** | **1,148** | 19 | — |
| Other [(1)] | **22** | **9** | **(10)** | **43** | **16** | 180 | — |
| Total production excl. offshore | **35,454** | **37,474** | **37,561** | **36,619** | **36,782** | 29,795 | 28,086 |
| Offshore Gulf of Mexico – Sold July 2004 | **—** | **—** | **—** | **—** | **—** | — | 4,865 |
| Total Company | **35,454** | **37,474** | **37,561** | **36,619** | **36,782** | 29,795 | 32,951 |

*(1) Primarily represents production from an offshore property retained from the sale in July 2004.*

As outlined in the above table, average production in 2006 increased 23% (6,987 BOE/d) over 2005 levels. The third quarter of 2005 was negatively affected by Hurricanes Katrina and Rita, as approximately 1,100 BOE/d is estimated as having been deferred during that period. If last year's average production is adjusted to include this deferred production, the average production increase between the two years would be reduced to approximately 19%. Of this adjusted annual increase, the January 2006 acquisition contributed approximately 2,148 BOE/d of the increase (36%) with 1,122 BOE/d attributable to the Mississippi – non-$CO_2$ floods and 1,026 BOE/d to Alabama fields, although a small portion of that increase was from our internal development efforts following the acquisition.

Production in the Mississippi – non-$CO_2$ floods area declined only modestly during 2006 (before giving effect to the January 2006 acquisition related increase noted above) and also during 2005. Recent drilling activity in the Heidelberg Selma Chalk (natural gas) has helped offset the gradual declines in oil production during 2006 and 2005.

See "$CO_2$ Operations" above for a discussion of the tertiary related production.

Our onshore Louisiana production for 2006 increased 1,773 BOE/d (29% increase) over the prior year's level, due primarily to production increases at Thornwell and South Chauvin Fields as a result of 2005 and 2006 drilling activity in that area. We drilled 15 successful wells during 2005, which boosted the production levels in early 2006. However, our Louisiana production is currently declining, as evidenced by the decline between the third and fourth quarters of 2006, as a result of depletion with insufficient new production to offset it as our 2006 success rate was not as good as it had been during 2005. Since our budget for 2007 has been reduced in this area, it is unlikely that our production here will increase during 2007. Our Louisiana properties are generally shorter-lived properties than our properties in most other areas, and therefore decline rather rapidly, requiring a consistent increase in new production in order to maintain production levels.

Our production in the Barnett Shale area during 2006 increased 2,723 BOE/d (127% increase) over our 2005 level, also as a result of increased drilling activity, with 46 wells drilled during 2006, as compared to 23 wells drilled during 2005. Production from this area has increased every quarter during the last two years, with additional modest increases expected during most of 2007 as we plan to drill 35 to 40 wells in this area during 2007, although this upward trend will not continue indefinitely. These wells are characterized by steep decline rates in their first year of production (as much as 50% to 60%), followed by a gradual leveling-off of production and a resultant slow decline rate, giving them an overall long production life.

As a result of the sale of our offshore properties in July 2004, total production decreased between fiscal year-ends 2004 and 2005. If 2004 is adjusted to exclude offshore production, overall production increased approximately 6% on a BOE/d basis during 2005, anchored by the increased production from our tertiary operations and from our Barnett Shale play, generally offset by overall declines in production from our onshore conventional properties in Mississippi and natural gas wells in Louisiana.

Our production for 2006 was weighted toward oil (62%) compared to 67% in 2005 and 58% in 2004, and we expect a similar weighting toward oil in 2007 due to our increasing emphasis on tertiary operations, unless we make an acquisition that is predominantly natural gas.

*Oil and Natural Gas Revenues.* Our oil and natural gas revenues have increased for each of the last two years, primarily as a result of higher commodity prices, offset in part in 2005 by lower production as a result of our 2004 sale of offshore properties, but supplemented in 2006 by a 23% increase in production levels. Between fiscal year-end 2005 and 2006, revenues increased by 31%. The 23% increase in production in 2006, as compared to production in 2005, increased oil and natural gas revenues by $128.8 million (77% of the total revenue increase) and the 6% higher overall commodity prices in 2006 (on a BOE basis) further increased revenue by $38.7 million (23% of the total revenue increase). Between 2004 and 2005, revenues increased by 23%. The overall increase in commodity prices contributed $148.0 million in additional revenues, (142% of the increase); partially offset by an overall decrease in revenues of $43.7 million (a negative 42% of the total revenue increase) related to the 10% lower production volumes.

Our net average realized crude oil price has increased each year, averaging 18% higher in 2006 over 2005 levels and 84% higher in 2005 over 2004 levels. Our net average realized natural gas price decreased 8% in 2006 as compared to 2005 levels, but the average price in 2005 was 38% higher than during 2004. On a weighted average net price per BOE, the increases in oil prices have more than offset the less consistent natural gas prices, resulting in a 6% increase in 2006 price levels as compared to 2005 prices and a 37% increase in 2005 prices as compared to 2004 levels.

Our net revenue is also affected by the difference between our net average price and the NYMEX quoted price (i.e., the NYMEX differential). During 2004 and continuing into 2005 and 2006, the discount for our heavier, sour crude (which predominantly applies to our Eastern Mississippi production) increased significantly, lowering our overall net price relative to NYMEX. Our net oil price averaged $4.91 below NYMEX during 2004, increased to $6.33 during 2005, and further increased to $6.41 during 2006. This occurred in spite of our increasing light sweet oil production from our Phase I tertiary operations, which should have improved our overall net price as such crude receives near NYMEX prices and is becoming a higher percentage of our overall production. However, as evident in 2005 and 2006, the oil market is subject to significant and sudden changes and it is difficult to forecast these trends, although our experience indicates that the discount or NYMEX differential for our heavier sour crude increases as NYMEX oil prices increase.

Our net natural gas prices relative to NYMEX fluctuate primarily as a result of the trend in the NYMEX prices during the month. Since most of our natural gas is sold on an index price that is set near the first of each month, the variance will decrease if NYMEX natural gas prices consistently decrease during the quarter and the opposite is true if prices are increasing. Our natural gas differentials relative to NYMEX improved in 2006 as compared to 2005, primarily due to decreasing natural gas prices throughout most of the year, but the opposite was true during 2005, when prices were generally rising. During 2006 our natural gas price averaged $0.13 above NYMEX, during 2005 we had an average discount to NYMEX of $0.49, and during 2004 we had an average premium of $0.02 to NYMEX. The NYMEX differential can also vary by area and our natural gas in the Barnett Shale area has a higher discount to NYMEX than the natural gas in Louisiana. Since our production in the Barnett area is growing and expected to increase again during 2007, while our Louisiana natural gas is generally declining, if prices remain consistent, we would expect our discount to NYMEX to gradually increase.

*Oil and Natural Gas Derivative Contracts.* During 2006, we made payments on our derivative contracts of $5.3 million, related to oil swaps put in place in late 2005 to protect the rate of return on the fields acquired in January 2006. These payments lowered our effective net oil price received in 2006 by $0.64 per Bbl. During 2005, we made payments on our derivative contracts of $16.8 million, down from $84.6 million paid out during the prior year. Our 2005 payments related to a natural gas collar, lowering our effective net natural gas price by $0.78 per Mcf. During 2004, we paid out $64.1 million on our derivative contracts ($9.10 per Bbl) and $20.4 million ($0.68 per Mcf) on our natural gas derivative contracts relating to swaps and collars we purchased one to two years earlier when commodity prices were lower. About $30.5 million of the payments related to swaps originally put in place to protect the rate of return for the COHO acquisition in August 2002.

Changing commodity prices cause fluctuations in the mark-to-market value adjustments of our derivative contracts. We recognized a non-cash gain of $25.1 million in 2006 as a result of the decreasing prices, primarily related to the 75 MMcf/d of natural gas swaps for calendar 2007 that we entered into during December 2006. During 2005, because of our decision to abandon hedge accounting as of January 1, 2005, we recognized a non-cash expense of $12.2 million primarily related to the amortization of the fair value of the derivative contracts in place as of January 1, 2005 over the remaining life of the contracts, which was generally 2005. During 2004, we recognized only $1.3 million of mark-to-market non-cash value adjustments as we were following hedge accounting prior to January 1, 2005. See also "Market Risk Management."

*Operating 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 (see discussion of those expenses under "$CO_2$ Operations" above), (ii) general cost inflation in our industry, (iii) increased personnel and related costs, (iv) higher fuel and energy costs to operate our properties, (v) increasing lease payments for certain of our tertiary operating facilities and equipment, and (vi) higher workover costs. The adoption of SFAS No. 123(R) effective January 1, 2006 (see "Overview – Operating results") also added approximately $1.5 million of non-cash charges to 2006 operating expenses, representing the stock compensation expense pertaining to operating personnel.

During 2006, operating costs averaged $12.46 per BOE, up from $9.98 per BOE in 2005 and $7.22 per BOE during 2004. Operating expenses of our tertiary operations increased from $24.6 million in 2004 to $40.4 million during 2005 and $65.0 million during 2006, as a result of increased tertiary activity. Tertiary operating expenses were particularly impacted by higher power and energy costs, higher costs for $CO_2$ and payments on leased facilities and equipment (see "$CO_2$ Operations" above). We expect this increase in tertiary operating costs to continue and to further increase our cost per BOE as these costs become a more significant portion of our total production and operations.

Workover expenses increased by over $11.5 million during 2006 as compared to 2005 levels, with over one-half of the increase relating to costs incurred on fields acquired during the year to bring them up to our operating standard. Workover expenses were higher in 2005 than in 2004 primarily due to expenses to repair a mechanical failure on one onshore Louisiana well.

Production taxes and marketing expenses generally change in proportion to commodity prices and therefore have been higher in each of the last three years along with the increasing commodity prices. The sale of our offshore properties in 2004 also contributed to the increase in production taxes and marketing expenses on a per BOE basis during 2005 and 2006, as most of our offshore properties were exempt from severance taxes.

### General and Administrative Expenses

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

| | Year Ended December 31, | | |
|---|---|---|---|
| Amounts in Thousands Except Per BOE and Employee Data | 2006 | 2005 | 2004 |
| Gross G&A expense | **$ 94,095** | $ 64,622 | $ 53,658 |
| State franchise taxes | **1,825** | 1,454 | 923 |
| Operator labor and overhead recovery charges | **(45,283)** | (32,452) | (28,048) |
| Capitalized exploration expense | **(7,623)** | (5,084) | (5,072) |
| Net G&A expense | **$ 43,014** | $ 28,540 | $ 21,461 |
| Average G&A expense per BOE | **$ 3.20** | $ 2.62 | $ 1.78 |
| Employees as of December 31 | **596** | 460 | 380 |

Gross G&A expenses increased $29.5 million, or 46%, between 2005 and 2006 and $11.0 million, or 20%, between 2004 and 2005. The single biggest increase during 2006 was due to the adoption of SFAS No. 123(R) in January 2006, which increased gross G&A expense by approximately $8.9 million during the year, representing the non-cash charge for stock compensation (stock options and stock appreciation rights) pertaining to personnel charged to G&A. In addition, 2006 expenses include approximately $3.5 million of non-cash compensation expense associated with the amortization of deferred compensation resulting from the issuance of restricted stock to officers and directors during 2004 which was already being expensed prior to the adoption of SFAS No. 123(R). During 2006, we also incurred a $5.3 million charge to earnings related to the modification of the vesting terms of certain restricted stock and stock options previously granted to our former Senior Vice-President of Operations, associated with his departure, and the expensing of approximately $750,000 related to the retirement of our Vice President of Marketing.

G&A also increased because of higher compensation costs due to additional employees, associated expenses and wage increases. During 2006 we had a net increase of 30% in our employee count related to our acquisitions and increased activity level and a 21% increase during the prior year. In addition, due to increased competitive pressures in the industry, our wages are increasing at a rate higher than general inflation and we expect this trend to continue. As an example, in 2006 we granted a 5% mid-year pay raise to all employees in order to remain competitive with industry compensation levels.

During 2005, we incurred approximately $1.4 million to provide food, water, gasoline, and other essential supplies to our employees and charitable organizations in Mississippi and Louisiana following the hurricanes. In addition, we have had higher professional service and consultant fees during 2005, primarily related to Sarbanes-Oxley compliance, investigation of hotline reports, and documentation and testing of our new software system that we began using in January 2005, as well as increased maintenance costs as a result of the change to our new software system. Many of these expenses were also applicable in 2006. These 2005 increases were offset by the absence of approximately $2.4 million of employee severance payments paid in 2004 related to the sale of our offshore properties in July 2004.

Higher operator overhead recovery charges resulting from incremental development activity helped to partially offset the increase in gross G&A, partially reduced by the impact of the offshore property sale. 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 the additional operated wells from acquisitions, additional tertiary operations, drilling activity during the past year and increased compensation expense (including the allocation of stock compensation to lease operating expense), the amount we recovered as operator labor and overhead charges increased by 40% between 2005 and 2006 and 16% between 2004 and 2005. Capitalized exploration costs increased in 2006 as compared to 2005 primarily due to increased compensation costs, most of which related to the expensing of stock based compensation associated with the adoption of SFAS No. 123(R). Capitalized exploration costs were relatively unchanged between 2005 and 2004 as the personnel reductions associated with the sale of our offshore properties in July 2004 offset the other increases. The net effect of the increases in gross G&A expenses, operator overhead recoveries and capitalized exploration costs was a 51% increase in net G&A expense between 2005 and 2006 and a 33% increase between 2004 and 2005.

### Interest and Financing Expenses

| | Year Ended December 31, | | |
|---|---|---|---|
| Amounts in Thousands Except Per BOE Data | 2006 | 2005 | 2004 |
| Cash interest expense | **$ 33,787** | $ 18,800 | $ 18,506 |
| Non-cash interest expense | **1,121** | 827 | 962 |
| Less: Capitalized interest | **(11,333)** | (1,649) | — |
| Interest expense | **$ 23,575** | $ 17,978 | $ 19,468 |
| Interest and other income | **$ 5,603** | $ 3,218 | $ 2,388 |
| Average net cash interest expense per BOE [1] | **$ 1.26** | $ 1.28 | $ 1.34 |
| Average debt outstanding | **$ 455,603** | $ 248,825 | $270,770 |
| Average interest rate [2] | **7.4%** | 7.6% | 6.8% |

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

*(2) Includes commitment fees but excludes amortization of debt issue costs.*

Interest expense increased in 2006, primarily due to substantially higher average debt levels offset in part by higher interest capitalized on our significant unevaluated properties, primarily related to our 2006 acquisitions. Debt levels were unusually low in the first half of 2005 following the sale of our offshore properties in mid-2004. Conversely, debt levels increased in the first quarter of 2006 following the $250 million acquisition which closed at the end of January 2006, funded by $150 million of subordinated debt issued in December 2005 and $100 million of bank debt borrowed at closing. The bank debt was repaid in April 2006 with the proceeds from an equity sale made that month (see "Overview – April 2006 Equity Offering"), but an additional $50 million was subsequently borrowed to fund the Delhi acquisition in May 2006 (see "Overview – Recent Acquisitions") and an additional $84 million for general working capital and the payment of the option on Hastings Field entered into in November 2006, leaving us with total bank debt of $134 million as of December 31, 2006.

Interest expense for 2005 decreased from 2004 levels primarily due to capitalized interest of $1.6 million relating to the construction of our $CO_2$ pipeline to East Mississippi and the payoff of our bank debt in the third quarter of 2004 with the proceeds from our offshore property sale. As a result of lower production because of our 2004 offshore sale and production deferred as a result of the two hurricanes, interest expense on a per BOE basis was not as positive as it was on an absolute basis.

| | Year Ended December 31, | | |
|---|---|---|---|
| Amounts in Thousands, Except Per BOE Data | 2006 | 2005 | 2004 |
| Depletion and depreciation of oil and natural gas properties | **$132,880** | $88,949 | $88,505 |
| Depletion and depreciation of $CO_2$ assets | **8,375** | 5,334 | 4,664 |
| Asset retirement obligations | **2,389** | 1,682 | 2,408 |
| Depreciation of other fixed assets | **5,521** | 2,837 | 1,950 |
| Total DD&A | **$149,165** | $98,802 | $97,527 |
| DD&A per BOE: | | | |
| Oil and natural gas properties | **$ 10.08** | $ 8.34 | $ 7.54 |
| $CO_2$ assets and other fixed assets | **1.03** | 0.75 | 0.55 |
| Total DD&A cost per BOE | **$ 11.11** | $ 9.09 | $ 8.09 |

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

Our proved reserves increased from 129.4 MMBOE as of December 31, 2004, to 152.6 MMBOE as of December 31, 2005, and further increased to 174.3 MMBOE as of December 31, 2006. Reserve quantities and associated production are only one side of the DD&A equation, with capital expenditures less accumulated depletion, asset retirement obligations less related salvage value, and projected future development costs making up the remainder of the calculation.

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 increased 22% between fiscal year-end 2005 and 2006, largely because we did not add many tertiary oil reserves during 2006, which historically have had a lower finding and development cost than our overall company average. We added approximately 17.8 MMBOE of reserves in the Barnett Shale during 2006 and approximately 6.0 MMBOE in our tertiary oil properties and only minor amounts elsewhere. Further, costs continued to climb in the industry throughout 2006, causing us not only to exceed our cost estimates on our 2006 projects, but also to re-evaluate and raise our future development costs on our proved undeveloped reserves. Lastly, we did not have any significant discoveries in our exploration program in Louisiana, which further contributed to an increase in our DD&A rate.

In general, 2006 was a transition year for us with regard to our tertiary oil reserves. Prior to 2006, many of our tertiary floods could be considered proven near the start of a project as they were analogous to Little Creek Field (an already-producing substantial tertiary flood) and thus it was not necessary to have a production response to $CO_2$ injections before we recognized proved reserves. Conversely, most of our new floods, including two that we started during 2006 (Soso and Martinville Fields), are not analogous and thus must have an oil production response to the $CO_2$ injections before we can recognize tertiary proved oil reserves in these fields, even though we believe there is a similar risk profile in flooding these fields. Due to several delays throughout the year, the Soso and Martinville floods were completed so late in 2006 that there was not a significant production response before year-end, a pre-condition to booking proved reserves in these fields.

We allocated approximately $124 million of our $250 million January 2006 acquisition costs and virtually all of the second quarter 2006 $50 million Delhi acquisition costs to unevaluated properties to reflect the significant potential reserves that we considered to be part of these acquisitions. As a result, these acquisitions did not materially affect our overall DD&A rate, as the amount included in our full cost pool was a cost per BOE relatively consistent with our overall DD&A rate.

Our DD&A rate on a per BOE basis increased 12% between 2004 and 2005, primarily due to rising costs and increases in capital spending. During 2005, we spent approximately $71.0 million on acquisitions, of which approximately $50.1 million was included in our full cost pool, with the balance becoming part of our unevaluated properties. Due to high commodity prices, our acquisition costs per BOE was around $14.60 per BOE, contributing to the higher DD&A rate. In addition, most of our future development cost estimates on our proved undeveloped reserves have been increased to reflect the rising costs in the industry.

Our DD&A rate for our $CO_2$ and other fixed assets has increased in both 2005 and 2006 as a result of the Free State $CO_2$ pipeline to eastern Mississippi, which went into service late in the first quarter of 2006, additional costs incurred drilling $CO_2$ wells during each year and higher associated future development costs, partially offset by an increase in $CO_2$ reserves from 2.7 Tcf as of December 31, 2004, to 4.6 Tcf as of December 31, 2005, to 5.5 Tcf as of December 31, 2006 (100% working interest basis before amounts attributable to Genesis volumetric production payments – see "$CO_2$ Operations – $CO_2$ Resources").

As part of the requirements of Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations, 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 as of December 31, 2004, to be $52.1 million ($21.5 million present value), with an estimated salvage value of $43.6 million, on an undiscounted basis. As of December 31, 2005, we estimated our retirement obligations to be $69.1 million ($27.1 million present value), with an estimated salvage value of $50.2 million. As of December 31, 2006, we estimated our retirement obligations to be $91.3 million ($41.1 million present value), with an estimated salvage value of $60.0 million, the increase related to our increased activity and higher cost estimates due to the inflation in our industry. DD&A is calculated on the increase to oil and natural gas and $CO_2$ properties, net of 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. We did not have any full cost pool ceiling test write-downs in 2004, 2005 or 2006.

### Income Taxes

| | Year Ended December 31, | | |
|---|---|---|---|
| Amounts in Thousands, Except Per BOE Amounts | 2006 | 2005 | 2004 |
| Current income tax expense | **$ 19,865** | $ 27,177 | $ 22,929 |
| Deferred income tax provision | **107,252** | 54,393 | 16,463 |
| Total income tax provision | **$ 127,117** | $ 81,570 | $ 39,392 |
| Average income tax provision per BOE | **$ 9.47** | $ 7.50 | $ 3.27 |
| Net effective tax rate | **38.6%** | 32.9% | 32.3% |
| Total net deferred tax asset (liability) | **$(229,925)** | $(129,474) | $(71,936) |

Our income tax provision for all three periods was based on an estimated statutory tax rate of approximately 39%. For 2004 and 2005, our net effective tax rate was lower than the statutory rate primarily due to the recognition of enhanced oil recovery credits ("EOR") which lowered our overall tax expense. For 2006, we did not earn any additional EOR credits because of the high oil prices during 2005, which completely phased out our ability to earn any additional credits. Under the recently adopted accounting rules of SFAS No. 123(R), a tax benefit, if any, for compensation expenses arising from the issuance of incentive stock options (the majority of our options issued prior to 2006) is not recognizable during the vesting period, the period during which they are expensed for book purposes, which also caused a slight increase in our effective tax rate in 2006. During the third quarter of 2004, we recognized approximately $21.0 million of current income taxes as a result of the sale of our offshore properties, which was a gain for income tax purposes. The taxes on the offshore sale were primarily alternative minimum taxes as we were able to offset the related regular tax with our net operating loss carryforwards that existed at that time. We no longer have any net operating loss carryforwards.

In all three periods, the current income tax expense represents our anticipated alternative minimum cash taxes that we cannot offset with EOR credits. As of December 31, 2006, we had an estimated $41.9 million of EOR credit carryforwards that we can utilize to reduce a portion of our cash taxes. These EOR credits do not begin to expire until 2020. Since the ability to earn additional enhanced oil recovery credits is reduced or even eliminated based on the level of oil prices, we do not expect to earn any EOR credits during 2007 because of the high oil prices during 2006. If oil prices remain at current levels or increase further in the future, we will not earn any additional EOR credits and once our existing EOR credits are utilized, our cash taxes will also increase.

### Results of Operations on a per BOE Basis

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

| | Year Ended December 31, | | |
|---|---|---|---|
| Per BOE Data | 2006 | 2005 | 2004 |
| Oil and natural gas revenues | **$53.37** | $50.49 | $36.88 |
| Loss on settlements of derivative contracts | **(0.39)** | (1.54) | (7.01) |
| Lease operating expenses | **(12.46)** | (9.98) | (7.22) |
| Production taxes and marketing expenses | **(2.71)** | (2.54) | (1.55) |
| Production netback | **37.81** | 36.43 | 21.10 |
| Non-tertiary $CO_2$ operating margin | **0.46** | 0.54 | 0.41 |
| General and administrative expenses | **(3.20)** | (2.62) | (1.78) |
| Net cash interest expense | **(1.26)** | (1.28) | (1.34) |
| Current income taxes and other | **(0.41)** | (1.50) | (1.78) |
| Changes in assets and liabilities relating to operations | **1.00** | 1.62 | (2.63) |
| Cash flow from operations | **34.40** | 33.19 | 13.98 |
| DD&A | **(11.11)** | (9.09) | (8.09) |
| Deferred income taxes | **(7.99)** | (5.00) | (1.37) |
| Non-cash derivative adjustments | **1.87** | (1.12) | (0.11) |
| Changes in assets and liabilities and other non-cash items | **(2.09)** | (2.67) | 2.43 |
| Net income | **$ 15.08** | $ 15.31 | $ 6.84 |

### Market Risk Management

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. The following table presents the carrying and fair values of our debt, along with average interest rates. We had $134 million of bank debt outstanding as of December 31, 2006, and $150 million outstanding at February 28, 2007. The fair value of the subordinated debt is based on quoted market prices. None of our debt has any triggers or covenants regarding our debt ratings with rating agencies.

| Amounts in Thousands | Maturity Dates 2007-2011 | Carrying Value | Fair Value |
|---|---|---|---|
| Fixed rate debt: | | | |
| Senior Subordinated Notes due 2013, net of discount (The interest rate on the subordinated debt is a fixed rate of 7.5%.) | **$ —** | **$ 223,786** | **$227,250** |
| Senior Subordinated Notes due 2015 (The interest rate on the subordinated debt is a fixed rate of 7.5%.) | **$ —** | **$ 150,000** | **$152,250** |

From time to time, we enter into various 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 hedged up to 75% of our anticipated production each 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. Since 2005 and beyond, we have entered into fewer derivative contracts, primarily because of our strong financial position resulting from our lower levels of debt relative to our cash flow from operations. We did make an exception in late 2006 when we swapped 80% to 90% of our forecasted 2007 natural gas production at a weighted average price of $7.96 per Mcf. We did this to protect our 2007 projected cash flow primarily because we currently plan to spend $200 million to $250 million more than we expect to generate in cash flow from operations (see "Capital Resources and Liquidity") and we did not want to be exposed to the risk of lower natural gas prices. These natural gas swaps had increased in value significantly during the short time we held them in 2006 (see value discussion below), although by February 23, 2007, this positive market value was virtually gone as natural gas prices rebounded during the first part of 2007.

When we make a significant acquisition, we generally attempt to hedge a large percentage, up to 100%, of the forecasted proved production for the subsequent one to three years following the acquisition in order to help provide us with a minimum return on our investment. As of December 31, 2006, we had derivative contracts in place related to our $250 million acquisition that closed on January 31, 2006, on which we entered into contracts to cover 100% of the estimated proved producing production at the time we signed the purchase and sale agreement. While these derivative contracts related to the acquisition represent approximately 7% of our estimated 2007 production, they are intended to help protect our acquisition economics related to the first three years of production from the proved producing reserves that we acquired. These swaps cover 2,000 Bbls/d for 2007 at a price of $58.93 per Bbl; and 2,000 Bbls/d for 2008 at a price of $57.34 per Bbl.

All of the mark-to-market valuations used for our financial 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. For a full description of our derivative contract positions at year-end 2006, see Note 10 to the Consolidated Financial Statements.

Effective January 1, 2005, for accounting purposes, we elected to de-designate our existing derivative contracts as hedges and began to account for them as speculative 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. During 2005, we amortized the December 31, 2004 balance in Accumulated Other Comprehensive Loss to earnings as that was the remaining life of those contracts. 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, 2006, our derivative contracts were recorded at their fair value, which was a net asset of approximately $15.7 million, an increase of $25.1 million from the $9.4 million fair value liability recorded as of December 31, 2005. This change is the result of lower commodity prices, primarily relating to our natural gas hedges for 2007 (see above). During 2006, we recognized total income related to our hedge contracts of $19.8 million, consisting of $5.3 million of cash payments on settlements of expired contracts and $25.1 million of income relating to market-to-market non-cash adjustments.

Based on NYMEX crude oil futures prices at December 31, 2006, we would expect to make future cash payments of $11.7 million on our crude oil commodity derivative contracts. If crude oil futures prices were to decline by 10%, we would expect to make future cash payments on our crude oil commodity derivative contracts of $2.1 million, and if futures prices were to increase by 10% we would expect to pay $21.4 million. Based on NYMEX natural gas futures prices at December 31, 2006, we would expect to receive future cash payments of $26.5 million on our natural gas commodity hedges. If natural gas futures prices were to decline by 10%, the amount we would expect to receive under our natural gas commodity hedges would increase to $45.6 million, and if future prices were to increase by 10% we would expect to receive $7.3 million.

### 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 guidance of SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," under which the net book value of assets are 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 commodity prices in effect at the end of the 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.

In our application of full cost accounting for our oil and gas producing activities, 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 2% of the previous year's estimates and have been both positive and negative.

Changes in commodity prices also affect our reserve quantities. During 2004, 2005 and 2006, the change to reserve quantities related to commodity prices was relatively small, less than in prior years, as prices were relatively high each year-end. 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 2006 DD&A rate from $11.60 per Bbl to approximately $11.12 per Bbl and a 5% decrease in our proved reserve quantities would have increased our DD&A rate to approximately $12.13 per Bbl. 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.

There can also be significant questions as to whether reserves are sufficiently supported by technical evidence to be considered proven. In some cases our proven reserves are less than what we believe to exist because additional evidence, including production testing, is required in order to classify the reserves as proven. In other cases, properties such as certain of our potential tertiary recovery projects may not have proven reserves assigned to them primarily because we have not yet completed a specific plan for development or firmly scheduled such development. We have a corporate policy whereby we generally do not book proved undeveloped reserves unless the project has been committed to internally, which normally means it is scheduled within the next one to two years (or at least the commencement of the project is scheduled in the case of longer-term multi-year projects such as waterfloods and tertiary recovery projects). Therefore, particularly with regard to potential reserves from tertiary recovery (our $CO_2$ operations), there is uncertainty as to whether the reserves should be included as proven or not. We also have a corporate policy whereby proved undeveloped reserves must be economic at long-term historical prices, which are usually significantly less than the year-end prices used in our reserve report. This also can have the effect of eliminating certain projects being included in our estimates of proved reserves, which projects would otherwise be included if undeveloped reserves were determined to be economic solely based on current prices in a high price environment, as was the case during the last three year-ends. (See Depletion, Depreciation and Amortization under Results of Operations above for a further discussion.) All of these factors and the decisions made regarding these issues can have a significant effect on our proven reserves and thus on our DD&A rate, full-cost ceiling test calculation, borrowing base and financial statements. See also discussion of requirements to book proven tertiary oil reserves at "Results of Operations – Depletion, Depreciation and Amortization."

### Asset Retirement Obligations

We have significant obligations related to the plugging and abandonment of our oil and gas wells, the removal of equipment and facilities from leased acreage, and returning such land to its original condition. SFAS No. 143 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.

### Accounting for Tertiary Injection Costs

We expense at the time of injection our costs associated with the $CO_2$ we use in our tertiary recovery operations. Our costs associated with the $CO_2$ we produce and inject are principally our costs to produce, transport and pay royalties. There are other acceptable alternatives in accounting for tertiary injectant costs, such as capitalizing these costs as oil and gas properties and depleting them over time, or expensing a portion and deferring a portion of the cost if the injectant material can be recovered and sold at a later time. Our decision to expense our tertiary injectant costs at the time of injection results in greater expense to us at the onset of a new tertiary recovery project as we may inject

$CO_2$ for several months before we experience any production response. Also, the injection of $CO_2$ will generally be higher in the earlier portions of the life of the project and will gradually decrease over time. We expensed costs for the $CO_2$ we injected of $18.1 million in 2006, $10.1 million in 2005, and $4.6 million in 2004.

### 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 prior to year-end 2005, net operating loss carry forwards. 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). 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, 2006 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 probable. A 1% increase in our effective tax rate would have increased our calculated income tax expense by approximately $3.3 million, $2.5 million, and $1.2 million for the years ended December 31, 2006, 2005 and 2004. See Note 7 to the Consolidated Financial Statements for further information concerning our income taxes.

### Oil and Gas Derivative Contracts

We enter into 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. Under SFAS No. 133, every derivative instrument is required to be recorded on the balance sheet as either an asset or a liability measured at its fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, the change in fair value of the derivative is recognized currently in earnings. If the derivative qualifies for cash flow hedge accounting, the change in fair value of the derivative is recognized in accumulated other comprehensive income (equity) to the extent that the hedge is effective and in the income statement to the extent it is ineffective.

Prior to 2005, we applied hedge accounting to our commodity derivative contracts, thereby recording a significant portion of the fair value changes to equity instead of income. We recognized losses on ineffectiveness on our hedges of $2.7 million for 2004. We measured and computed hedge effectiveness on a quarterly basis. If a hedging instrument became ineffective, hedge accounting was discontinued and any deferred gains or losses on the cash flow hedge remained in accumulated other comprehensive income until the periods during which the hedges would have otherwise expired. If we determined it probable that a hedged forecasted transaction will not occur, deferred gains or losses on the hedging instrument were recognized in earnings immediately.

As of January 1, 2005, we abandoned hedge accounting. 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 had continued to apply hedge accounting treatment as permitted by SFAS No. 133, 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 2006 and 2005, we recognized expense (income) of ($25.1) million and $4.5 million, respectively, related to changes in the fair market value of our derivative contracts. For 2004, if we had not chosen to designate hedge accounting treatment to our oil and natural gas derivative contracts, or if none of our derivative contracts had qualified for hedge accounting treatment, we estimate that our net income would have increased by approximately $25.0 million.

### Stock Compensation Plans

Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS No. 123(R), "Share-Based Payment" using the modified prospective application method described in the statement. Among other items, SFAS 123(R) eliminates the use of APB 25 and the intrinsic value method of accounting, and requires companies to 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. Under the modified prospective application method, effective January 1, 2006, we began to recognize compensation expense for the unvested portion of awards outstanding as of December 31, 2005, over the remaining service periods, and for new awards granted or modified after January 1, 2006.

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, 2006, there was $11.9 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 1.2 years.

**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**

In July 2006, the FASB issued Interpretation 48, "Accounting for Uncertainty in Income Taxes" ("FIN 48"). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS No. 109, "Accounting for Income Taxes." This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 requires recognition of the impact of a tax position in the Company's financial statements if that position is more likely than not of being sustained on audit, based on the technical merits of the position. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The provisions of FIN 48 are effective as of the beginning of the Company's 2007 fiscal year, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. We are still evaluating the potential impact of this interpretation on the Company's financial statements.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements." SFAS No. 157 defines fair value, establishes a framework for measuring fair value in accordance with accounting principles generally accepted in the United States, and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, with earlier application encouraged. Any amounts recognized upon adoption as a cumulative effect adjustment will be recorded to the opening balance of retained earnings in the year of adoption. We have not yet determined the impact of this Statement on the Company's financial condition and results of operations.

**Forward-Looking Information**

The statements contained in this Annual Report on Form 10-K that are not historical facts, including, but not limited to, statements found in 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. 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, production rates and volumes or forecasts thereof, hydrocarbon reserves, hydrocarbon or expected reserve quantities and values, potential reserves from tertiary operations, hydrocarbon prices, pricing assumptions based on current and projected oil and gas prices, liquidity, regulatory matters, mark-to-market values, competition, long-term forecasts of production, finding cost, rates of return, estimated costs or changes in costs, future capital expenditures and overall economics and other variables surrounding our tertiary 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, inaccurate cost estimates, fluctuations in the prices of goods and services, the uncertainty of drilling results and reserve estimates, operating hazards, acquisition risks, requirements for capital or its availability, general economic conditions, competition and government regulations, 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.

This Annual Report is not deemed to be soliciting material or to be filed with the Securities and Exchange Commission or subject to the liabilities of Section 18 of the Securities Act of 1934.

## 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 46 through 48.

## Item 8. Financial Statements and Supplementary Data

## MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management, including the Chief Executive Officer and the Chief Financial Officer, is responsible for establishing and maintaining adequate internal controls over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our system of 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. Our 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.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2006. In making this assessment, our management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control-Integrated Framework*. Based on our management's assessment, we have concluded that our internal control over financial reporting was effective as of December 31, 2006, based on those criteria.

Our management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their audit report, which appears herein.

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have completed integrated audits of Denbury Resources Inc.'s consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

**Consolidated financial statements**

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, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes 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. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, the Company changed its method of accounting for stock-based compensation costs in 2006.

**Internal control over financial reporting**

Also, in our opinion, management's assessment, included in the accompanying "Management's Report on Internal Control Over Financial Reporting", that the Company maintained effective internal control over financial reporting as of December 31, 2006 based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control - Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

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

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Dallas, Texas

February 28, 2007

## Consolidated Balance Sheets

| (In Thousands, Except Shares) | December 31, 2006 | 2005 |
|---|---|---|
| **ASSETS** | | |
| CURRENT ASSETS | | |
| Cash and cash equivalents | **$ 53,873** | $ 165,089 |
| Accrued production receivable | **72,279** | 65,611 |
| Related party receivable – Genesis | **119** | 1,312 |
| Trade and other receivables, net of allowance of $315 and $289 | **24,260** | 25,887 |
| Derivative assets | **26,883** | — |
| Deferred tax assets | **5,855** | 41,284 |
| Total current assets | **183,269** | 299,183 |
| PROPERTY AND EQUIPMENT | | |
| Oil and natural gas properties (using full cost accounting) | | |
| Proved | **2,226,942** | 1,669,579 |
| Unevaluated | **293,657** | 46,597 |
| $CO_2$ properties and equipment | **267,483** | 210,046 |
| Other | **43,133** | 34,647 |
| Less accumulated depletion and depreciation | **(951,447)** | (804,899) |
| Net property and equipment | **1,879,768** | 1,155,970 |
| Investment in Genesis | **10,640** | 10,829 |
| Deposits on properties under option or contract | **49,002** | 26,425 |
| Other assets | **17,158** | 12,662 |
| Total Assets | **$ 2,139,837** | $ 1,505,069 |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| CURRENT LIABILITIES | | |
| Accounts payable and accrued liabilities | **$ 139,111** | $ 104,840 |
| Oil and gas production payable | **52,244** | 41,821 |
| Derivative liabilities | **4,302** | 2,759 |
| Deferred revenue – Genesis | **4,070** | 4,070 |
| Short-term capital lease obligations | **671** | 574 |
| Total current liabilities | **200,398** | 154,064 |
| LONG-TERM LIABILITIES | | |
| Capital lease obligations | **6,387** | 5,870 |
| Long-term debt, net of discount | **507,786** | 373,591 |
| Asset retirement obligations | **39,331** | 25,297 |
| Derivative liabilities | **6,834** | 6,624 |
| Deferred revenue – Genesis | **28,843** | 33,023 |
| Deferred tax liability | **235,780** | 170,758 |
| Other | **8,419** | 2,180 |
| Total long-term liabilities | **833,380** | 617,343 |
| COMMITMENTS AND CONTINGENCIES (NOTE 11) | | |
| STOCKHOLDERS' EQUITY | | |
| Preferred stock, $.001 par value, 25,000,000 shares authorized; none issued and outstanding | **—** | — |
| Common stock, $.001 par value, 250,000,000 shares authorized; 120,506,815 and 115,038,531 shares issued at December 31, 2006 and 2005, respectively | **121** | 115 |
| Paid-in capital in excess of par | **616,046** | 443,283 |
| Retained earnings | **498,032** | 295,575 |
| Treasury stock, at cost, 370,327 and 340,337 shares at December 31, 2006 and 2005, respectively | **(8,140)** | (5,311) |
| Total stockholders' equity | **1,106,059** | 733,662 |
| Total Liabilities and Stockholders' Equity | **$ 2,139,837** | $ 1,505,069 |

*See Notes to Consolidated Financial Statements.*

## Consolidated Statements of Operations

| (In Thousands, Except Per Share Data) | Year Ended December 31, 2006 | 2005 | 2004 |
|---|---|---|---|
| REVENUES | | | |
| Oil, natural gas and related product sales | | | |
| Unrelated parties | **$715,061** | $544,408 | $ 381,253 |
| Related party – Genesis | **1,496** | 4,647 | 63,524 |
| $CO_2$ sales and transportation fees | **9,376** | 8,119 | 6,276 |
| Loss on effective hedge contracts | **—** | — | (70,469) |
| Interest income and other | **5,603** | 3,218 | 2,388 |
| Total revenues | **731,536** | 560,392 | 382,972 |
| EXPENSES | | | |
| Lease operating expenses | **167,271** | 108,550 | 87,107 |
| Production taxes and marketing expenses | **31,993** | 23,553 | 17,569 |
| Transportation expense – Genesis | **4,358** | 4,029 | 1,168 |
| $CO_2$ operating expenses | **3,190** | 2,251 | 1,338 |
| General and administrative | **43,014** | 28,540 | 21,461 |
| Interest, net of amounts capitalized of $11,333 in 2006 and $1,649 in 2005 | **23,575** | 17,978 | 19,468 |
| Depletion, depreciation and amortization | **149,165** | 98,802 | 97,527 |
| Commodity derivative expense (income) | **(19,828)** | 28,962 | 15,358 |
| Total expenses | **402,738** | 312,665 | 260,996 |
| EQUITY IN NET INCOME (LOSS) OF GENESIS | **776** | 314 | (136) |
| INCOME BEFORE INCOME TAXES | **329,574** | 248,041 | 121,840 |
| INCOME TAX PROVISION | | | |
| Current income taxes | **19,865** | 27,177 | 22,929 |
| Deferred income taxes | **107,252** | 54,393 | 16,463 |
| NET INCOME | **$202,457** | $ 166,471 | $ 82,448 |
| NET INCOME PER SHARE – BASIC | **$ 1.74** | $ 1.49 | $ 0.75 |
| NET INCOME PER SHARE – DILUTED | **$ 1.64** | $ 1.39 | $ 0.72 |
| WEIGHTED AVERAGE COMMON SHARES OUTSTANDING | | | |
| Basic | **116,550** | 111,743 | 109,741 |
| Diluted | **123,774** | 119,634 | 114,603 |

*See Notes to Consolidated Financial Statements.*

## Consolidated Statements of Cash Flows

| (In Thousands) | Year Ended December 31, 2006 | 2005 | 2004 |
|---|---|---|---|
| CASH FLOW FROM OPERATING ACTIVITIES: | | | |
| Net income | **$ 202,457** | $ 166,471 | $ 82,448 |
| Adjustments needed to reconcile to net cash flow provided by operations: | | | |
| Depreciation, depletion and amortization | **149,165** | 98,802 | 97,527 |
| Deferred income taxes | **107,252** | 54,393 | 16,463 |
| Deferred revenue - Genesis | **(4,180)** | (3,080) | (2,399) |
| Stock based compensation | **17,246** | 4,121 | 1,601 |
| Non-cash derivative adjustments | **(25,129)** | 12,201 | 1,270 |
| Income tax benefit from equity awards | **—** | 9,218 | 1,706 |
| Amortization of debt issue costs and other | **1,603** | 1,257 | 1,577 |
| Changes in assets and liabilities relating to operations: | | | |
| Accrued production receivable | **(5,474)** | (21,388) | (19,776) |
| Trade and other receivables | **1,712** | (14,924) | 7,475 |
| Derivative assets and liabilities | **—** | — | (7,519) |
| Other assets | **(672)** | 129 | (166) |
| Accounts payable and accrued liabilities | **7,038** | 38,202 | (10,522) |
| Oil and gas production payable | **10,422** | 16,966 | 2,641 |
| Other liabilities | **370** | (1,408) | (3,674) |
| NET CASH PROVIDED BY OPERATING ACTIVITIES | **461,810** | 360,960 | 168,652 |
| CASH FLOW USED FOR INVESTING ACTIVITIES: | | | |
| Oil and natural gas expenditures | **(507,327)** | (308,366) | (167,001) |
| Acquisitions of oil and gas properties | **(319,000)** | (70,870) | (11,069) |
| Change in accrual for capital expenditures | **13,195** | 18,196 | — |
| Investment in Genesis | **—** | (4,257) | — |
| Acquisition of $CO_2$ assets and $CO_2$ capital expenditures | **(63,586)** | (78,726) | (50,265) |
| Net purchases of other assets | **(10,531)** | (6,441) | (5,210) |
| Deposits on properties under option or contract | **(11,159)** | (21,917) | (4,507) |
| Increase in restricted cash | **(981)** | (249) | (542) |
| Purchases of short-term investments | **—** | — | (76,517) |
| Sales of short-term investments | **—** | 57,133 | 19,350 |
| Net proceeds from $CO_2$ production payment – Genesis | **—** | 14,363 | 4,636 |
| Net proceeds from sales of properties and equipment | **42,762** | 17,447 | 10,042 |
| Sale of Denbury Offshore, Inc. | **—** | — | 187,533 |
| NET CASH USED FOR INVESTING ACTIVITIES | **(856,627)** | (383,687) | (93,550) |
| CASH FLOW FROM FINANCING ACTIVITIES: | | | |
| Bank repayments | **(249,000)** | (64,800) | (88,000) |
| Bank borrowings | **383,000** | 64,800 | 13,000 |
| Payments on capital lease obligations | **(580)** | (521) | (32) |
| Income tax benefit from equity awards | **16,575** | — | — |
| Issuance of subordinated debt | **—** | 150,000 | — |
| Issuance of common stock | **139,834** | 12,392 | 13,168 |
| Purchase of treasury stock | **(5,544)** | (5,119) | (3,977) |
| Costs of debt financing | **(684)** | (1,975) | (410) |
| NET CASH PROVIDED BY (USED FOR) FINANCING ACTIVITIES | **283,601** | 154,777 | (66,251) |
| NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS | **(111,216)** | 132,050 | 8,851 |
| Cash and cash equivalents at beginning of year | **165,089** | 33,039 | 24,188 |
| Cash and cash equivalents at end of year | **$ 53,873** | $ 165,089 | $ 33,039 |

*See Notes to Consolidated Financial Statements.*

## Consolidated Statements of Change in Stockholders' Equity

| (Dollar amounts in Thousands) | Common Stock ($.001 Par Value) Shares | Common Stock ($.001 Par Value) Amount | Paid-In Capital in Excess of Par | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Treasury Stock (at cost) Shares | Treasury Stock (at cost) Amount | Total Stockholders' Equity |
|---|---|---|---|---|---|---|---|---|
| BALANCE – DECEMBER 31, 2003 | 54,190,042 | $ 54 | $401,709 | $ 46,656 | $(27,113) | 8,162 | $ (104) | $ 421,202 |
| Repurchase of common stock | — | — | — | — | — | 200,000 | (3,977) | (3,977) |
| Issued pursuant to employee stock purchase plan | — | — | 396 | — | — | (115,090) | 2,035 | 2,431 |
| Issued pursuant to employee stock option plan | 1,264,284 | 2 | 10,737 | — | — | — | — | 10,739 |
| Issued pursuant to directors' compensation plan | 3,551 | — | 82 | — | — | — | — | 82 |
| Restricted stock grants | 1,150,000 | 1 | (1) | — | — | — | — | — |
| Stock based compensation | — | — | 1,601 | — | — | — | — | 1,601 |
| Income tax benefit from equity awards | — | — | 4,821 | — | — | — | — | 4,821 |
| Derivative contracts, net | — | — | — | — | 22,349 | — | — | 22,349 |
| Unrealized loss on available-for-sale securities | — | — | — | — | (24) | — | — | (24) |
| Net income | — | — | — | 82,448 | — | — | — | 82,448 |
| BALANCE – DECEMBER 31, 2004 | 56,607,877 | 57 | 419,345 | 129,104 | (4,788) | 93,072 | (2,046) | 541,672 |
| Repurchase of common stock | — | — | — | — | — | 142,287 | (5,119) | (5,119) |
| Issued pursuant to employee stock purchase plan | — | — | 887 | — | — | (80,869) | 1,854 | 2,741 |
| Issued pursuant to employee stock option plan | 949,051 | 1 | 9,650 | — | — | — | — | 9,651 |
| Issued pursuant to directors' compensation plan | 3,502 | — | 119 | — | — | — | — | 119 |
| Restricted stock grants | 10,000 | — | — | — | — | — | — | — |
| Two-for-one stock split | 57,468,101 | 57 | (57) | — | — | 185,847 | — | — |
| Stock-based compensation | — | — | 4,121 | — | — | — | — | 4,121 |
| Income tax benefit from equity awards | — | — | 9,218 | — | — | — | — | 9,218 |
| Derivative contracts, net | — | — | — | — | 4,764 | — | — | 4,764 |
| Unrealized gain on available-for-sale securities | — | — | — | — | 24 | — | — | 24 |
| Net income | — | — | — | 166,471 | — | — | — | 166,471 |
| BALANCE – DECEMBER 31, 2005 | 115,038,531 | 115 | 443,283 | 295,575 | — | 340,337 | (5,311) | 733,662 |
| Repurchase of common stock | **—** | **—** | **—** | **—** | **—** | **167,255** | **(5,544)** | **(5,544)** |
| Issued pursuant to employee stock purchase plan | **—** | **—** | **1,245** | **—** | **—** | **(137,265)** | **2,715** | **3,960** |
| Issued pursuant to employee stock option plans | **2,012,472** | **2** | **11,018** | **—** | **—** | **—** | **—** | **11,020** |
| Issued pursuant to directors' compensation plan | **4,441** | **—** | **134** | **—** | **—** | **—** | **—** | **134** |
| Restricted stock grants | **129,987** | **—** | **—** | **—** | **—** | **—** | **—** | **—** |
| Restricted stock grants —forfeited | **(171,211)** | **—** | **—** | **—** | **—** | **—** | **—** | **—** |
| Stock based compensation | **—** | **—** | **18,941** | **—** | **—** | **—** | **—** | **18,941** |
| Income tax benefit from equity awards | **—** | **—** | **16,575** | **—** | **—** | **—** | **—** | **16,575** |
| Issuance of common stock | **3,492,595** | **4** | **124,850** | **—** | **—** | **—** | **—** | **124,854** |
| Net income | **—** | **—** | **—** | **202,457** | **—** | **—** | **—** | **202,457** |
| BALANCE – DECEMBER 31, 2006 | **120,506,815** | **$121** | **$616,046** | **$498,032** | **$ —** | **370,327** | **$(8,140)** | **$1,106,059** |

*See Notes to Consolidated Financial Statements.*

## Consolidated Statements of Comprehensive Income

| (In Thousands) | Year Ended December 31, 2006 | 2005 | 2004 |
|---|---|---|---|
| NET INCOME | **$202,457** | $166,471 | $ 82,448 |
| Other comprehensive income (loss), net of tax: | | | |
| Change in fair value of derivative contracts, net of tax of ($19,328) | **—** | — | (31,535) |
| Reclassification adjustments related to settlements of derivative contracts, net of tax of $2,920 and $33,025, respectively | **—** | 4,764 | 53,884 |
| Unrealized gain (loss) on securities available for sale, net of tax of $15 and ($15), respectively | **—** | 24 | (24) |
| COMPREHENSIVE INCOME | **$202,457** | $171,259 | $104,773 |

*See 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 (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. In 2002, one of our subsidiaries acquired the general partner of Genesis Energy, L.P. (Genesis), a publicly traded master limited partnership. During 2003, we acquired additional Genesis limited partnership units, increasing our ownership interest in Genesis from 2% to 9.25%. We account for our ownership interest in Genesis under the equity method of accounting. Even though we have significant influence over the limited partnership in our role as general partner, because our control is limited by the Genesis limited partnership agreement we do not consolidate Genesis. See Note 3 for more information regarding our related party transactions with Genesis. All material intercompany balances and transactions have been eliminated. We have evaluated our consolidation of variable interest entities in accordance with FASB Interpretation No. 46, "Consolidation of Variable Interest Entities," and have concluded that we do not have any variable interest entities that would require consolidation.

**Stock Split**

On October 19, 2005, 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 100,000,000 shares to 250,000,000 shares and to split our common stock on a 2-for-1 basis. Stockholders of record on October 31, 2005, 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.

**Oil and Natural Gas Operations**

*A) 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 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.

*B) Depletion and depreciation.* The costs capitalized, including production equipment, 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 associated with our oil and gas producing activites was $10.54 in 2006, $8.69 in 2005 and $7.82 in 2004.

*C) 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.

*D) 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; (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. The cost center ceiling test is prepared quarterly.

*E) 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.

*F) Proved Reserves.* See Note 14 for information on our proved oil and natural gas reserves and the basis on which they are recorded.

**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.

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, 2006 and 2005, 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 enter into 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. Derivative financial instruments are recorded on the balance sheet as either an asset or a liability measured at fair value. Effective January 1, 2005, we elected to discontinue hedge accounting for our oil and natural gas derivative contracts and accordingly de-designated our derivative instruments from hedge accounting treatment. As a result of this change, we began accounting for our oil and natural gas derivative contracts as speculative contracts in the first quarter of 2005. As speculative contracts, the changes in the fair value of these instruments are recognized in income in the period of change.

### Financial Instruments with Off-Balance-Sheet Risk and Concentrations of Credit Risk

Our financial instruments that are exposed to concentrations of credit risk consist primarily of cash equivalents, trade and accrued production receivables and the derivative hedging 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 derivative hedging 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. 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. We evaluate our $CO_2$ assets for impairment by comparing our expected future revenues from these assets to their net carrying value.

### 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, 2006 and 2005, we had approximately $7.6 million and $6.7 million, respectively, of restricted cash and investments held in escrow accounts for future site reclamation costs. These balances are recorded at cost and are included in "Other assets" in the Consolidated Balance Sheets. The estimated fair market value of these investments at December 31, 2006 and 2005, was virtually 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, stock appreciation rights ("SARs"), non-vested restricted stock and any other convertible securities outstanding.

For each of the three years in the period ended December 31, 2006, there were no adjustments to net income for purposes of calculating basic and diluted net income per common share. In April 2006, we issued 3,492,595 shares of common stock in a public offering – See Note 8, Stockholders' Equity.

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

| | Year Ended December 31, | | |
|---|---|---|---|
| (In Thousands) | 2006 | 2005 | 2004 |
| Weighted average common shares – basic | **116,550** | 111,743 | 109,741 |
| Potentially dilutive securities: | | | |
| Stock options and SARs | **6,188** | 6,931 | 4,827 |
| Restricted stock | **1,036** | 960 | 35 |
| Weighted average common shares – diluted | **123,774** | 119,634 | 114,603 |

The weighted average common shares – basic amount in 2006 and 2005 excludes 1.4 million and 2.0 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 dilution impact of these shares on our earnings per share calculation may increase in future periods, depending on the market price of our common stock during those periods. Stock options and SARs to purchase approximately 128,000 shares in 2006, 184,000 shares in 2005 and 80,000 shares in 2004 were outstanding but excluded from the diluted net income per common share calculations, as their exercise prices exceeded the average market price of our common stock during the respective periods, therefore, their inclusion would be anti-dilutive to the calculations.

**Stock-Based Compensation**

In December 2004, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standard ("SFAS") No. 123(R), "Share Based Payment," which is a revision of SFAS No. 123, "Accounting for Stock-Based Compensation." SFAS No. 123(R) supersedes Accounting Principles Board Opinion 25 ("APB 25"), "Accounting for Stock Issued to Employees," and amends SFAS No. 95, "Statement of Cash Flows." Generally, the approach in SFAS No. 123(R) is similar to the approach described in SFAS No. 123. However, SFAS No. 123(R) requires all share-based compensation to employees, including grants of employee stock options, to be recognized in our consolidated financial statements based on estimated fair value.

We adopted SFAS No. 123(R) on January 1, 2006, using the modified prospective application method described in the statement. Under the modified prospective method, effective January 1, 2006, we began to recognize compensation expense for the unvested portion of awards outstanding as of December 31, 2005, over the remaining service periods, and for new awards granted or modified after January 1, 2006. See Note 9 for further discussion regarding our stock compensation plans.

**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.

**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, and (v) estimates made in the calculation of income taxes. 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.

#### Recent Accounting Pronouncements

In July 2006, the FASB issued Interpretation 48, "Accounting for Uncertainty in Income Taxes" ("FIN 48"). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS No. 109, "Accounting for Income Taxes." This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 requires recognition of the impact of a tax position in the Company's financial statements if that position is more likely than not of being sustained on audit, based on the technical merits of the position. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The provisions of FIN 48 are effective as of the beginning of the Company's 2007 fiscal year, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. We are still evaluating the potential impact of this interpretation on the Company's financial statements.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements." SFAS No. 157 defines fair value, establishes a framework for measuring fair value in accordance with accounting principles generally accepted in the United States, and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, with earlier application encouraged. Any amounts recognized upon adoption as a cumulative effect adjustment will be recorded to the opening balance of retained earnings in the year of adoption. We have not yet determined the impact of this Statement on the Company's financial condition and results of operations.

## Note 2. Acquisitions and Divestitures

#### 2006 Acquisitions

On January 31, 2006, we completed an acquisition of three producing oil properties that are future potential $CO_2$ tertiary oil flood candidates: Tinsley Field, approximately 40 miles northwest of Jackson, Mississippi, Citronelle Field in Southwest Alabama, and the smaller South Cypress Creek Field near the Company's Eucutta Field in Eastern Mississippi. In 2006 we began our initial tertiary development work at Tinsley Field, consisting primarily of planning, land and engineering work, with more extensive development and facility construction planned for 2007. The timing of tertiary development at Citronelle Field is uncertain, as we will need to build a 60- to 70-mile pipeline extension of our Free State $CO_2$ pipeline (pipeline from Jackson Dome to East Mississippi) before flooding can commence, and South Cypress Creek will probably be flooded following our initial development of our other East Mississippi properties.

The adjusted purchase price for these properties was approximately $250 million (including the $25 million of earnest money we had deposited at December 31, 2005, which was included in our Consolidated Balance Sheet in "Deposits on properties under option or contract"), after adjusting for interim net cash flow between the effective date and closing date of the acquisition, and minor purchase price adjustments. The adjusted purchase price of $250 million was allocated between proved and unevaluated oil and natural gas properties based on a risk adjusted analysis of the total estimated value of the proved, probable, and possible reserves acquired. Based on this analysis, approximately $126 million was assigned to proved properties and approximately $124 million assigned to unevaluated properties. The unevaluated costs are currently excluded from the amortization base and will be transferred to the amortization base as we develop and test the tertiary recovery projects planned in these fields. We currently estimate that this development will take place over the next two to five years. The acquisition was funded with the proceeds of $150 million of senior subordinated notes issued in December 2005 and $100 million of bank financing under the Company's then existing credit facility (repaid in late April 2006 with proceeds from a $125 million equity offering at that time).

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 have achieved $200 million in net operating revenue, as defined. Delhi is also a future potential $CO_2$ tertiary oil flood candidate, one that will require construction of a $CO_2$ pipeline before flooding can commence, which will likely be an extension of the currently planned $CO_2$ pipeline from Jackson Dome to Tinsley Field. Our goal is to have this $CO_2$ line installed within the next two years, with initial oil production from tertiary operations currently anticipated during 2009. Currently, there is neither significant oil production nor proved oil reserves at Delhi. The purchase price of approximately $50 million was allocated between proved and unevaluated oil and natural gas properties based on a risk adjusted analysis of the total estimated value of the proved, probable, and possible reserves acquired. Based on the analysis, approximately $1 million was assigned to evaluated properties and approximately $49 million was assigned to unevaluated properties. The unevaluated costs are currently excluded from the amortization base and will be transferred to the amortization base over the next three to five years as we develop and test the tertiary recovery projects planned in this field. The acquisition was funded with our bank credit facility.

The operating results of the acquired properties were included in our financial statements beginning in February 2006, except for Delhi, which was included beginning June 2006. We have not presented any pro forma information for the acquired properties as the pro forma effect was not material to our results of operations for the years ended December 31, 2006 and 2005.

**2006 Purchase Option Contract**

During November 2006, we entered into an agreement with a subsidiary of Venoco, Inc. that gives us the option to purchase their interest in Hastings Field, a strategically significant potential tertiary flood candidate located near Houston, Texas, between November 1, 2008 and November 1, 2009. The agreement provides for the parties to agree upon a purchase price at the time of the exercise of the option, which may be paid in cash or through a volumetric production payment; failing agreement as to price, the price will be determined by a pre-designated independent petroleum engineering firm using specified criteria for calculation of the discounted present value of the proved reserves at that time. As consideration for the option agreement, we made a payment of $37.5 million in November 2006 and are required to make additional payments totaling $12.5 million over the next two years. We have recorded this payment and the discounted present value of the required additional payments, which total $49 million, in "Deposits on properties under option or contract" in our December 31, 2006 Consolidated Balance Sheet. Upon exercise of the option to purchase the Hastings Field, the deposit will be transferred to oil and natural gas properties. We will evaluate the option for impairment and if circumstances arise that indicate the future acquisition will not occur, we will recognize expense for this option as appropriate.

**2005 Acquisitions**

Our acquisitions in 2005 included the purchase of additional interest and acreage in the Barnett Shale area ($34.2 million), additional interest in the Eucutta Field ($8.0 million), and the purchase of two oil fields that may be potential tertiary flood candidates in the future, Lake St. John ($16.1 million) and Cranfield ($1.1 million).

**Sale of Denbury Offshore, Inc.**

On July 20, 2004, we closed the sale of Denbury Offshore, Inc., a subsidiary that held our offshore assets, for $200 million (before adjustments) to Newfield Exploration Company. The sale price was based on the asset value of the offshore assets as of April 1, 2004, which means that the net operating cash flow (defined as revenue less operating expenses and capital expenditures) from these properties that we received between April 1 and closing, as well as expenses of the sale and other contractual adjustments, reduced the purchase price to approximately $187 million. We excluded from the sale a discovery well drilled at High Island A-6 during 2004, and certain deep rights at West Delta 27 that we sold for $1.8 million in December 2004, but retained a carried interest in a deep exploratory well.

Our financial results for 2004 include production, revenues, operating expenses, and capital expenditures of the offshore properties through July 19, 2004. Revenues of Denbury Offshore, Inc. included in our 2004 results were $62.6 million. We recorded the proceeds from the sale as a reduction to our full cost pool. We paid approximately $21 million of current income taxes relating to the sale and paid approximately $2.4 million of employee severance costs in 2004. We used $85 million of the sales proceeds to retire our bank debt.

Our offshore properties made up approximately 12.5% of our year-end 2003 proved reserves (approximately 96 Bcfe as of December 31, 2003) and represented approximately 25% of our 2004 second quarter production (9,114 BOE/d).

## Note 3. Related Party Transactions – Genesis

**Interest in and Transactions with Genesis**

Denbury is the general partner and owns an aggregate 9.25% interest in Genesis Energy, L.P. ("Genesis"), a publicly traded master limited partnership. Genesis' primary business activities include gathering, marketing, and transportation of crude oil and natural gas, and wholesale marketing of $CO_2$, primarily in Mississippi, Texas, Alabama and Florida.

We account for our 9.25% ownership in Genesis under the equity method of accounting as we have significant influence over the limited partnership; however, our control is limited under the limited partnership agreement and therefore we do not consolidate Genesis. Our equity in Genesis' net income (loss) for 2006 was $0.8 million, for 2005 was $0.3 million, and for 2004 was $(0.1) million. Denbury received pro-rata distribution from Genesis of $0.9 million in 2006, $0.5 million in 2005 and $0.5 million in 2004. We also received $120,000 in each of the last three years in directors' fees for certain officers of Denbury that are board members of Genesis. There are no guarantees by Denbury or any of its other subsidiaries of the debt of Genesis or of Genesis Energy, Inc. Our investment in Genesis of $11.5 million exceeded our percentage of net equity in the limited partnership at the time of acquisition by approximately $2.2 million, which represents goodwill and is not subject to amortization. The fair value of our investment in Genesis was in excess of $25.4 million at December 31, 2006, based on quoted market values of Genesis' publicly traded limited partnership units.

During 2006, we invested a total of $3.0 million in a Louisiana petroleum coke-to-ammonia project that is in the development stage. All of our investment may later be redeemed, with a return, or converted to equity after construction financing for the project has been obtained. If the project is built, we plan to take up to 100% of the $CO_2$ produced from this plant. Genesis has also invested in this project, with its total commitment not to exceed $1.0 million.

**Oil Sales and Transportation Services**

Prior to September 2004, including the period prior to our investment in Genesis, we sold certain of our oil production to Genesis. Beginning in September 2004, we discontinued most of our direct sales to Genesis and began to transport our crude oil using Genesis' common carrier pipeline to a sales point where it is sold to third party purchasers. For these transportation services, we pay Genesis a fee for the use of their pipeline and trucking services. We expensed $4.4 million in 2006, $4.0 million in 2005 and $1.2 million in 2004 for these transportation services.

**Transportation Leases**

In late 2004 and early 2005, we entered into 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, 2006 and 2005, we had $5.9 million and $6.4 million, respectively, of capital lease obligations with Genesis recorded as liabilities in our Consolidated Balance Sheets, of which $0.6 million was current in both periods.

**$CO_2$ 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, 2006, 2005 and 2004 $32.9 million, $37.1 million and $25.8 million, respectively, was recorded as deferred revenue of which $4.1 million was included in current liabilities at both December 31, 2006 and 2005. We recognized deferred revenue of $4.2 million, $3.1 million and $2.4 million for the years ended December 31, 2006, 2005 and 2004, 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 $0.17 per Mcf of $CO_2$. For these services, we recognized revenues of $4.6 million, $3.5 million, and $2.7 million for the years ended December 31, 2006, 2005 and 2004, respectively.

At December 31, 2006, 2005 and 2004, we had a net receivable from Genesis of $0.1 million, $1.3 million and $0.7 million, respectively, associated with all of the transactions described above.

## 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, 2006 and 2005.

| | Year Ended December 31, | |
|---|---|---|
| (In Thousands) | 2006 | 2005 |
| Beginning asset retirement obligation | **$27,088** | $21,540 |
| Liabilities incurred and assumed during period | **10,159** | 3,091 |
| Revisions in estimated cash flows | **2,791** | 1,765 |
| Liabilities settled during period | **(1,320)** | (990) |
| Accretion expense | **2,389** | 1,682 |
| Ending asset retirement obligation | **$41,107** | $27,088 |

At both December 31, 2006 and 2005, $1.8 million 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 2006 and 2005 are primarily for properties acquired. We have escrow accounts that are legally restricted for certain of our asset retirement obligations. The balances of these escrow accounts were $7.6 million at December 31, 2006, and $6.7 million at December 31, 2005, and are included in "Other assets" in our Consolidated Balance Sheets.

## Note 5. Property and Equipment

| (In Thousands) | December 31, 2006 | 2005 |
|---|---|---|
| OIL AND NATURAL GAS PROPERTIES: | | |
| Proved properties | **$2,226,942** | $1,669,579 |
| Unevaluated properties | **293,657** | 46,597 |
| Total | **2,520,599** | 1,716,176 |
| Accumulated depletion and depreciation | **(907,911)** | (775,390) |
| NET OIL AND NATURAL GAS PROPERTIES | **1,612,688** | 940,786 |
| $CO_2$ properties and equipment | **267,483** | 210,046 |
| Accumulated depletion and depreciation | **(24,997)** | (15,544) |
| NET $CO_2$ PROPERTIES | **242,486** | 194,502 |
| Capital leases | **7,985** | 6,997 |
| Accumulated depletion and depreciation | **(1,631)** | (835) |
| NET CAPITAL LEASES | **6,354** | 6,162 |
| Other | **35,148** | 27,650 |
| Accumulated depletion and depreciation | **(16,908)** | (13,130) |
| NET OTHER | **18,240** | 14,520 |
| NET PROPERTY AND EQUIPMENT | **$1,879,768** | $1,155,970 |

**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. A summary of the unevaluated properties excluded from oil and natural gas properties being amortized at December 31, 2006 and 2005, and the year in which they were incurred follows:

| | December 31, 2006 | | | | |
|---|---|---|---|---|---|
| | Costs Incurred During: | | | | |
| (In Thousands) | 2006 | 2005 | 2004 | Prior | Total |
| Property acquisition costs | **$193,554** | **$11,906** | **$1,244** | **$ 411** | **$ 207,115** |
| Exploration and development | **70,624** | **1,657** | **805** | **2,397** | **75,483** |
| Capitalized interest | **11,059** | **—** | **—** | **—** | **11,059** |
| Total | **$275,237** | **$13,563** | **$2,049** | **$2,808** | **$293,657** |

| | December 31, 2005 | | | | |
|---|---|---|---|---|---|
| | Costs Incurred During: | | | | |
| (In Thousands) | 2005 | 2004 | 2003 | Prior | Total |
| Property acquisition costs | $ 30,622 | $ 2,368 | $1,007 | $ 527 | $34,524 |
| Exploration and development | 6,493 | 2,245 | 1,107 | 2,228 | 12,073 |
| Total | $ 37,115 | $ 4,613 | $ 2,114 | $ 2,755 | $ 46,597 |

Property acquisition costs for 2006 are primarily associated with our acquisitions of four $CO_2$ tertiary oil field candidates, Tinsley Field, Citronelle Field, South Cypress Creek Field and Delhi Field. See Note 2 – "Acquisitions and Divestitures." Property acquisition costs for 2005 are primarily associated with our acquisition of Lake St. John Field. Exploration and development costs for 2006 are primarily associated with our $CO_2$ tertiary oil fields that are under development and did not have proved reserves at December 31, 2006. 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.

## Note 6. Notes Payable and Long-Term Indebtedness

| | December 31, | |
|---|---|---|
| (In Thousands) | 2006 | 2005 |
| 7.5% Senior Subordinated Notes due 2015 | **$150,000** | $150,000 |
| 7.5% Senior Subordinated Notes due 2013 | **225,000** | 225,000 |
| Discount on Senior Subordinated Notes due 2013 | **(1,214)** | (1,409) |
| Senior bank loan | **134,000** | — |
| Capital lease obligations – Genesis | **5,869** | 6,444 |
| Capital lease obligations | **1,189** | — |
| Total | **514,844** | 380,035 |
| Less current obligations | **671** | 574 |
| Long-term debt and capital lease obligations | **$514,173** | $379,461 |

**7.5% Senior Subordinated Notes due 2015**

On December 21, 2005, we issued $150 million of 7.5% Senior Subordinated Notes due 2015 ("2015 Notes"). The 2015 Notes 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 (see Note 2, "Acquisitions and Divestitures"). Pending the funding of this transaction in January 2006, the net proceeds were used to repay the borrowings under our bank credit facility with the balance temporarily invested in short-term investments and included as "Cash and cash equivalents" in our December 31, 2005 Consolidated Balance Sheet.

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. In addition, prior to December 15, 2008, we may at our option on one or more occasions redeem up to 35% of the 2015 Notes at a redemption price of 107.5% with the net cash proceeds from a stock offering. 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 and we used most of our $218.4 million of net proceeds from the offering, after underwriting and issuance costs, to retire our then existing $200 million of 9% Senior Subordinated Notes due 2008, including the Series B notes.

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 redemption prices: 103.75% after April 1, 2008, 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.

In connection with our internal reorganization to a holding-company organizational structure, we entered into a First Supplemental Indenture dated December 29, 2003, which did not require the consent of the holders of the 2013 Notes. The supplemental indenture made Denbury Resources Inc. and Denbury Onshore, LLC, co-obligors of this debt. All of our significant subsidiaries continue to fully and unconditionally guarantee this debt. There were no other significant changes as part of the amendment.

**Senior Bank Loan**

On September 14, 2006, we entered into a Sixth Amended and Restated Credit Agreement with our nine banks that modified our previous bank credit agreement. The new agreement (i) improves the credit pricing under the agreement, (ii) extends the term of the credit arrangements by two and one-half years to September 14, 2011, (iii) increases the borrowing base from $300 million to $500 million, (iv) increases the maximum facility size from $300 million to $800 million, and (v) makes other minor modifications and corrections. Under the new agreement, the commitment amount remained at $150 million. However, in December 2006, we increased our commitment amount to $250 million. The borrowing base represents the amount that can be borrowed from a credit standpoint based on our 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 we make in excess of the commitment amount ($250 million), up to the borrowing base limit ($500 million), although the banks are not obligated to fund any amount in excess of the commitment amount. The new credit agreement maintains the structure of semi-annual reviews of the borrowing base and commitment amount on April 1 and October 1.

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. At December 31, 2006, we had exceeded the hedge limitation of 85% of our forecasted natural gas production and we have obtained a waiver of this covenant from the banks, which is effective through the end of 2007. Otherwise, we were in compliance with all of our bank covenants as of December 31, 2006. 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, 2006, we had $134 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 6.35% at December 31, 2006. The next scheduled redetermination of the borrowing base will be as of April 1, 2007, based on December 31, 2006 assets and proved reserves.

**Indebtedness Repayment Schedule**

At December 31, 2006, our indebtedness, excluding the discount on our senior subordinated debt, is repayable over the next five years and thereafter as follows:

(In Thousands)

| | |
|---|---|
| 2007 | **$ 671** |
| 2008 | **736** |
| 2009 | **1,018** |
| 2010 | **890** |
| 2011 | **135,024** |
| Thereafter | **377,719** |
| Total indebtedness | **$516,058** |

## Note 7. Income Taxes

Our income tax provision is as follows:

| (In Thousands) | Year Ended December 31, 2006 | 2005 | 2004 |
|---|---|---|---|
| Current income tax expense: | | | |
| Federal | **$ 16,033** | $26,659 | $22,166 |
| State | **3,832** | 518 | 763 |
| Total current income tax expense | **19,865** | 27,177 | 22,929 |
| Deferred income tax expense: | | | |
| Federal | **97,902** | 44,191 | 12,352 |
| State | **9,350** | 10,202 | 4,111 |
| Total deferred income tax expense | **107,252** | 54,393 | 16,463 |
| Total income tax expense | **$127,117** | $81,570 | $39,392 |

In conjunction with the sale of Denbury Offshore, Inc. in 2004, we utilized all of our federal tax net operating loss carryforwards and paid alternative minimum taxes of approximately $21 million. At December 31, 2006, we have approximately $19.8 million in state net operating loss carryforwards that begin to expire in 2013. As of December 31, 2006, we have an estimated $41.9 million of enhanced oil recovery credits to carry forward related to our tertiary operations. These credits will begin to expire in 2020. Deferred income taxes relate to temporary differences based on tax laws and statutory rates in effect at the December 31, 2006 and 2005, balance sheet dates. We believe that we will be able to utilize all of our deferred tax assets at December 31, 2006, and therefore have provided no valuation allowance against our deferred tax assets.

At December 31, 2006 and 2005, our deferred tax assets and liabilities were as follows:

| (In Thousands) | December 31, 2006 | 2005 |
|---|---|---|
| Deferred tax assets: | | |
| Loss carryforwards – state | **$ 792** | $ 983 |
| Tax credit carryover | **14,103** | 14,103 |
| Enhanced oil recovery credit carryforwards | **41,856** | 42,127 |
| Other | **7,791** | 1,196 |
| Total deferred tax assets | **64,542** | 58,409 |
| Deferred tax liabilities: | | |
| Property and equipment | **(283,983)** | (187,883) |
| Derivative hedging contracts | **(10,484)** | — |
| Total deferred tax liabilities | **(294,467)** | (187,883) |
| Total net deferred tax liability | **$(229,925)** | $ (129,474) |

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, 2006 | 2005 | 2004 |
|---|---|---|---|
| Income tax provision calculated using the federal statutory income tax rate | **$115,351** | $86,814 | $42,644 |
| State income taxes | **13,183** | 9,922 | 4,874 |
| Enhanced oil recovery credits | **—** | (17,142) | (7,986) |
| Other | **(1,417)** | 1,976 | (140) |
| Total income tax expense | **$127,117** | $81,570 | $39,392 |

## Note 8. Stockholders' Equity

### Stock Issuance

On April 25, 2006, we closed on the $125 million sale (net to Denbury) of 3,492,595 shares of common stock in a public offering. We used the net proceeds from the offering to repay then current borrowings under our bank credit facility, which were $120 million as of April 25, 2006, the majority of which was incurred to partially fund our $250 million acquisition of three properties in January 2006.

### Stock Split

On October 19, 2005, 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 100,000,000 shares to 250,000,000 shares and to split our common stock on a 2-for-1 basis. Stockholders of record on October 31, 2005, 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.

### Authorized

We are authorized to issue 250 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 Repurchase Plan

Between August 2003 and June 30, 2005, Denbury had an active stock repurchase plan ("Plan") to purchase shares of our common stock on the NYSE in order for such repurchased shares to be reissued to our employees who participate in Denbury's Employee Stock Purchase Plan (see *Employee Stock Purchase Plan* below). During 2003, we purchased 200,000 shares at an average cost of $6.39 per share and reissued 183,676 of those shares under Denbury's Employee Stock Purchase Plan. In 2004, we repurchased into treasury 400,000 shares at an average cost of $9.95 per share and reissued 230,180 treasury shares under the Employee Stock Purchase Plan. In the first six months of 2005, we repurchased into treasury 200,000 shares under the Plan at an average cost of $15.82 per share and reissued 130,831 treasury shares under our Employee Stock Purchase Plan. Our repurchase program expired as of June 30, 2005, and the Board of Directors currently does not plan to renew the Plan until a significant portion of the treasury shares have been used under our Employee Stock Purchase Plan. In 2006, all of our share repurchases were associated with shares surrendered to the Company to cover tax withholding upon the vesting of restricted stock 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 3,500,000 shares of common stock. As of Decem ber 31, 2006, there were 315,106 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 $1.7 million, $1.2 million, and $1.0 million for the years ended December 31, 2006, 2005 and 2004, 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. Up to 3% of an employee's compensation, as defined by the plan, is matched by Denbury at 100% and an employee's contribution between 3% and 6% of compensation is matched by Denbury at 50%. Denbury's match is vested immediately. During 2006, 2005 and 2004, Denbury's matching contributions were approximately $1.6 million, $1.2 million, and $1.0 million, respectively, to the 401(k) Plan.

## Note 9. Stock Compensation Plans

**Incentive Programs**

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. 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 5.0 million shares of common stock are authorized for issuance pursuant to the 2004 Plan, of which awards covering no more than 2,750,000 shares may be issued in the form of restricted stock or performance vesting awards. At December 31, 2006, a total of 1,226,054 shares were available for future issuance of awards, of which only 471,224 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 or permanent disability 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.

During August 2004 through January 2005, the Board of Directors, based on a recommendation by the Board's Compensation Committee, awarded the officers of Denbury a total of 2,200,000 shares of restricted stock and the independent directors of Denbury a total of 120,000 shares of restricted stock, 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 the certificates until certain requirements are met. With respect to the 2,200,000 shares of restricted stock granted to officers of Denbury, 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. With respect to the 65% of the awards that vest over five years, on each annual vesting date, 66-2/3% of the vested shares may be delivered to the holder with the remaining 33-1/3% retained and held in escrow until the holder's separation from the Company. With respect to the 120,000 restricted shares issued to Denbury's independent board members, the shares vest 20% per year over five years. For these directors' shares, on each annual vesting date, 40% of such vested shares may be delivered to the holder with the remaining 60% retained and held in escrow until the holder's separation from the Company. During 2006, a total of 129,987 shares of restricted stock were granted to officers and certain members of our management group.

Mr. Worthey, Senior Vice President of Operations, left Denbury effective June 5, 2006. Mr. Worthey had served as an officer of the Company since September 1, 1992. The Board of Directors modified certain of his outstanding long-term equity incentives awarded to him during 2003 and 2004. As a result of the modification, Mr. Worthey retained stock options covering 63,090 shares of Denbury common stock that pursuant to their original terms vest in either January 2007 or January 2008, and received accelerated vesting of 136,500 shares of restricted stock that originally were set to vest between mid-August 2006 and mid-August 2008. The options have an average weighted exercise price of $6.26 per share and were granted in early 2003 and early 2004; the restricted stock was awarded in August 2004. The compensation cost resulting from the modifications was approximately $5.3 million and was included in "General and administrative expenses" in the Consolidated Statement of Operations for the year ended December 31, 2006. No significant cash compensation was paid to Mr. Worthey upon separation. As part of Mr. Worthey's separation, he also entered into non-competition and consulting agreements covering a period of 27 months.

During the third quarter of 2006, our Vice President of Marketing announced his retirement and departed the Company on August 31, 2006, in connection with which we expensed approximately $750,000 related to options and restricted stock that he held.

Total compensation expense charged against income for stock-based compensation was $17.2 million (including the $5.3 million resulting from modification of Mr. Worthey's equity awards discussed above) for the year ended December 31, 2006. Part of this expense, $1.5 million, was included in "Lease operating expenses" for stock compensation expense associated with our field employees, and the remaining $15.7 million was 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 $4.6 million for the year ended December 31, 2006. Share-based compensation capitalized as part of "Oil and Natural Gas Properties" was $1.7 million for the year ended December 31, 2006.

Effective January 1, 2006, we adopted SFAS No. 123(R) to account for our employee stock based compensation. Prior to 2006, we accounted for stock-based compensation utilizing the recognition and measurement principles of Accounting Principles Board Opinion 25 (APB 25), "Accounting for Stock Issued to Employees," and its related interpretations. Under these principles, no compensation expense for stock options was reflected in net income as long as the stock options had an exercise price equal to the quoted market price of the underlying common stock on the date of grant. For restricted stock grants, we recognize compensation expense equal to the intrinsic value of the stock on the date of grant over the applicable vesting periods. The following table illustrates the effect on net income and net income per common share for 2004 and 2005 as if we had applied the fair value recognition and measurement provisions of SFAS No. 123, as amended by SFAS No. 148, in accounting for our stock-based compensation.

| | Year Ended December 31, | |
|---|---|---|
| Amounts in thousands, except per share amounts | 2005 | 2004 |
| Net income, as reported | $166,471 | $82,448 |
| Add: stock-based compensation included in reported net income, net of related tax effects | 2,765 | 977 |
| Less: stock-based compensation expense applying fair value based method, net of related tax effects | 8,425 | 3,713 |
| Pro-forma net income | $160,811 | $ 79,712 |
| NET INCOME PER COMMON SHARE | | |
| As reported: | | |
| Basic | $ 1.49 | $ 0.75 |
| Diluted | 1.39 | 0.72 |
| Pro forma: | | |
| Basic | $ 1.44 | $ 0.73 |
| Diluted | 1.36 | 0.69 |

Prior to the adoption of SFAS No. 123(R) on January 1, 2006, we did not assume the capitalization of any stock-based compensation in our SFAS No. 123 pro forma net income. As a result, no stock-based compensation expense is reflected as being capitalized in the table above.

Beginning in 2006, an appropriate portion of stock-based compensation associated with our employees involved in our exploration and drilling activities has been capitalized as part of our "Oil and Natural Gas Properties" in the Consolidated Balance Sheet. The effect of applying SFAS No. 123(R) during the year ended December 31, 2006, was to decrease net income by approximately $6.4 million for stock compensation expense that would only have been presented in footnote disclosures under the old requirements of SFAS No. 123. The effect on earnings per share for the year ended December 31, 2006 was a decrease of $0.05 per both basic and diluted share. Additionally, cash flow from operations was lower and cash flow from financing activities was higher by approximately $16.6 million for the year ended December 31, 2006, associated with the tax benefit for tax deductions in excess of recognized compensation expenses that is now required to be reported as a financing cash flow.

**Stock Options and SARs**

The fair value of each stock option or SAR award is estimated on the date of grant using the Black-Scholes option pricing model using 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.

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Weighted average fair value of options granted | **$12.64** | $6.94 | $3.22 |
| Risk free interest rate | **4.52%** | 3.80% | 3.34% |
| Expected life | **4.9 to 6.9 years** | 5 years | 5 years |
| Expected volatility | **41.1%** | 42.6% | 46.8% |
| Dividend yield | **—** | — | — |

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

| | Year Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2006 | | 2005 | | 2004 | |
| | Number of Options | Weighted Average Price | Number of Options | Weighted Average Price | Number of Options | Weighted Average Price |
| Outstanding at beginning of year | **9,406,072** | **$ 8.07** | 8,880,314 | $ 5.25 | 10,652,432 | $4.60 |
| Granted | **517,155** | **27.16** | 2,483,254 | 16.29 | 2,019,620 | 7.18 |
| Exercised | **(2,016,326)** | **5.53** | (1,797,146) | 5.37 | (2,528,568) | 4.25 |
| Forfeited | **(424,441)** | **11.05** | (160,350) | 8.86 | (1,263,170) | 4.89 |
| Outstanding at end of year | **7,482,460** | **9.91** | 9,406,072 | 8.07 | 8,880,314 | 5.25 |
| Exercisable at end of year | **2,369,552** | **$ 5.32** | 2,509,635 | $ 4.50 | 3,088,824 | $4.81 |

The total intrinsic value of stock options and SARs exercised during the years ended December 31, 2006, 2005 and 2004 was approximately $49.3 million, $24.8 million and $13.2 million, respectively. The total fair value of stock options and SARs vested during the years ended December 31, 2006, 2005 and 2004 was approximately $6.0 million, $3.4 million and $1.8 million, respectively. The aggregate intrinsic value of stock options and SARs outstanding at December 31, 2006, was approximately $133.8 million and these options and SARs have a weighted-average remaining contractual life of 6.3 years. The aggregate intrinsic value of options exercisable at December 31, 2006, was approximately $53.2 million and these stock options and SARs have a weighted-average remaining contractual life of 4.0 years.

A summary of the status of our non-vested stock options and SARs as of December 31, 2006, and the changes during the year ended December 31, 2006, is presented below:

| Non-vested stock options and SARs | Shares | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Non-vested at January 1, 2006 | **6,896,437** | **$ 4.25** |
| Granted | **517,155** | **12.64** |
| Vested | **(1,876,243)** | **3.20** |
| Forfeited | **(424,441)** | **5.02** |
| Non-vested at December 31, 2006 | **5,112,908** | **5.41** |

As of December 31, 2006, there was $11.9 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 1.2 years. Cash received from stock option exercises under share-based payment arrangements for the year ended December 31, 2006, 2005 and 2004 was $11.1 million, $9.7 million and $10.7 million, respectively. The tax benefit realized from the exercises of stock options and SARs totaled $14.7 million for 2006, $8.6 million for 2005, and $4.8 million for 2004.

**Restricted Stock**

As of December 31, 2006, we had issued 2,449,987 shares of restricted stock pursuant to the 2004 Plan and have recorded deferred compensation expense of $25.1 million, the fair market value of the shares on the grant dates net of estimated forfeitures of $2.2 million. This expense is amortized over the applicable five-year, four-year, or retirement date vesting periods. As of December 31, 2006, there was $14.0 million of unrecognized compensation expense related to non-vested restricted stock grants. This unrecognized compensation cost is expected to be recognized over a weighted-average period of 2.9 years.

A summary of the status of our non-vested restricted stock grants, and the changes during the year ended December 31, 2006, is presented below:

| Non-vested Restricted Stock Grants | Shares | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Non-vested at January 1, 2006 | **2,014,000** | **$10.15** |
| Granted | **129,987** | **28.92** |
| Vested | **(528,815)** | **10.19** |
| Forfeited | **(171,211)** | **10.31** |
| Non-vested at December 31, 2006 | **1,443,961** | **11.80** |

The total vesting date fair value of restricted stock vested during the years ended December 31, 2006 and 2005 was $17.4 million and $7.1 million, respectively.

## Note 10. Derivative Instruments and Hedging Activities

Effective January 1, 2005, we elected to discontinue hedge accounting treatment for financial statement purposes for our oil and natural gas derivative contracts and accordingly de-designated our derivative instruments from hedge accounting treatment in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activites." As a result of this change, we began accounting for our oil and natural gas derivative contracts as speculative contracts in the first quarter of 2005. As speculative contracts, the changes in the fair value of these instruments are recognized in income in the period of change. Additionally, the balance remaining in "Accumulated Comprehensive Loss" at December 31, 2004, related to the designated derivative contracts was amortized over the remaining life of the contracts, all of which expired in 2005.

From time to time, we enter into various derivative contracts to economically hedge 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, prior to 2005, we hedged up to 75% of our anticipated production each 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. Since 2005 and beyond, we have entered into fewer derivative contracts, primarily because of our strong financial position resulting from our lower levels of debt relative to our cash flow from operations. We did make an exception in late 2006, when we swapped 80% to 90% of our forecasted 2007 natural gas production at a weighted average price of $7.96 per Mcf. We did this to protect our 2007 projected cash flow primarily because we currently plan to spend more than we expect to generate from cash flows from operations and we did not want to be exposed to the risk of lower natural gas prices.

When we make a significant acquisition, we generally attempt to hedge a large percentage, up to 100%, of the forecasted production for the subsequent one to three years following the acquisition in order to help provide us with a minimum return on our investment. As of December 31, 2006, we had derivative contracts in place related to the $250 million acquisition that closed January 31, 2006, on which we entered into contracts to cover 100% of the estimated proved production for three years at the time we signed the purchase and sale agreement. All of the mark-to-market valuations used for our financial 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, which are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures, and diversification.

The following is a summary of the net loss on our commodity contracts that qualified for hedge accounting treatment, covering those periods prior to our discontinuance of hedge accounting effective January 1, 2005, and is included in "Loss on effective hedge contracts" in our Consolidated Statements of Operations:

| (In Thousands) | Year Ended December 31, 2004 |
|---|---|
| Settlements of hedge contracts – Oil | $(50,072) |
| Settlements of hedge contracts – Gas | (20,397) |
| Loss on effective hedge contracts | $(70,469) |

The following is a summary of "Commodity derivative expense (income)," included in our Consolidated Statements of Operations. These amounts are associated with derivative contracts not designated as accounting hedges or the ineffective portion of contracts that qualified as accounting hedges in 2004.

| | Year Ended December 31, | | |
|---|---|---|---|
| (In Thousands) | 2006 | 2005 | 2004 |
| Settlements of derivative contracts – oil | **$ 5,302** | $ — | $14,088 |
| Settlements of derivative contracts – gas | **—** | 16,761 | — |
| Hedge ineffectiveness on contracts qualifying for hedge accounting | **—** | — | 2,687 |
| Reclassification of accumulated other comprehensive income balance | **—** | 7,684 | (955) |
| Fair value adjustments to derivative contracts | **(25,130)** | 4,517 | (462) |
| Commodity derivative expense (income) | **$(19,828)** | $28,962 | $15,358 |

**Derivative Contracts at December 31, 2006:**

Crude Oil Contracts:

| Type of Contract and Period | NYMEX Contract Prices Per Bbl | | Estimated Fair Value at December 31, 2006 (In Thousands) |
|---|---|---|---|
| | Bbls/d | Swap Price | |
| Swap Contracts | | | |
| Jan. 2007 - Dec. 2007 | **2,000** | **58.93** | **$(4,302)** |
| Jan. 2008 - Dec. 2008 | **2,000** | **57.34** | **(6,834)** |

Natural Gas Contracts:

| Type of Contract and Period | NYMEX Contract Prices Per MMBtu | | Estimated Fair Value at December 31, 2006 (In Thousands) |
|---|---|---|---|
| | MMBtu/d | Swap Price | |
| Swap Contracts | | | |
| Jan. 2007 - Dec. 2007 | **20,000** | **7.99** | **$ 7,340** |
| Jan. 2007 - Dec. 2007 | **40,000** | **7.96** | **14,252** |
| Jan. 2007 - Dec. 2007 | **15,000** | **7.95** | **5,291** |

At December 31, 2006, our derivative contracts were recorded at their fair value, which was a net asset of $15.7 million.

## Note 11. Commitments and Contingencies

We have operating leases for the rental of equipment, office space, and vehicles that totaled $101.4 million, $37.2 million, and $16.6 million as of December 31, 2006, 2005, and 2004, respectively. During the last four 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 $41.1 million during 2006, $17.3 million during 2005 and $6.9 million during 2004 with associated required monthly payments of $431,000 for the 2006 leases, $223,000 for the 2005 leases and $91,000 for the 2004 leases. Leases entered into prior to 2006 have seven-year terms and the leases entered into in 2006 have a 10-year term. Rental expense for operating leases totaled $14.1 million in 2006, $8.2 million in 2005, and $5.8 million in 2004.

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.

At December 31, 2006, long-term commitments for these items require the following future minimum rental payments:

| (In Thousands) | Capital Leases | Operating Leases |
|---|---|---|
| 2007 | **$ 1,291** | **$ 13,056** |
| 2008 | **1,291** | **12,667** |
| 2009 | **1,529** | **11,857** |
| 2010 | **1,291** | **11,527** |
| 2011 | **1,291** | **10,967** |
| Thereafter | **3,335** | **41,304** |
| Total minimum lease payments | **10,028** | **$101,378** |
| Less: Amount representing interest | **(2,970)** | |
| Present value of minimum lease payments | **$ 7,058** | |

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 391 Bcf of $CO_2$ to these customers over the next 17 years, with a maximum volume required in any given year of approximately 105 MMcf/d. 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 will be significantly less than the contractual commitment. Given the size of our proven $CO_2$ reserves at December 31, 2006 (approximately 5.5 Tcf before deducting approximately 210.5 Bcf for the 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 delivery obligations.

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**

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

## Note 12. Supplemental Information

**Significant Oil and Natural Gas Purchasers**

Oil and natural gas sales are made on a day-to-day basis or under short-term contracts at the current area market price. The loss of any purchaser would not be expected to have a material adverse effect upon our operations. For the year ended December 31, 2006, two purchasers each accounted for 10% or more of our oil and natural gas revenues: Marathon Ashland Petroleum LLC (28%) and Hunt Crude Oil Supply Co. (18%). For the year ended December 31, 2005, we had three significant purchasers that each accounted for 10% or more of our oil and natural gas revenues: Marathon Ashland Petroleum LLC (28%), Hunt Crude Oil Supply Co. (20%) and Sunoco, Inc. (13%). For the year ended December 31, 2004, two purchasers each accounted for 10% or more of our oil and natural gas revenues: Hunt Crude Oil Supply Co. (21%) and Genesis (14%).

**Accounts Payable and Accrued Liabilities**

| (In Thousands) | December 31, 2006 | 2005 |
|---|---|---|
| Accounts payable | **$ 57,637** | $ 53,306 |
| Accrued exploration and development costs | **36,830** | 23,635 |
| Accrued lease operating expense | **8,178** | 5,435 |
| Hastings purchase option – current | **6,794** | — |
| Accrued compensation | **6,361** | 5,287 |
| Accrued interest | **5,233** | 4,582 |
| Taxes payable | **4,447** | 1,374 |
| Asset retirement obligations – current | **1,776** | 1,791 |
| Other | **11,855** | 9,430 |
| Total | **$139,111** | $104,840 |

**Supplemental Cash Flow Information**

| | Year Ended December 31, 2006 | 2005 | 2004 |
|---|---|---|---|
| Interest paid, net of amounts capitalized | **$21,514** | $16,622 | $18,099 |
| Interest capitalized | **11,333** | 1,649 | — |
| Income taxes paid | **4,210** | 21,000 | 20,726 |

During 2006, we capitalized $11.0 million of interest on our significant unevaluated properties, primarily related to the two recent acquisitions. Additionally, we capitalized $0.3 million in 2006 and $1.6 million in 2005, of interest relating to the construction of our $CO_2$ pipeline to East Mississippi. We recorded a non-cash increase to property and debt in the amount of $1.2 million in 2006, $2.4 million in 2005 and $4.6 million in 2004, related to capital leases. In 2004, we issued 2,300,000 shares of restricted stock with a market value of $23.3 million on the date of grant. In 2005, we issued 20,000 shares of restricted stock with a market value of $0.3 million on the date of grant. In 2006, we issued 129,987 shares of restricted stock with a market value of $3.8 million on the date of grant. See Note 9 "Stock Compensation Plans – Restricted Stock."

In November 2006, we entered into an agreement for the option to purchase an oil property for an upfront payment of $37.5 million, plus required additional payments totaling $12.5 million during the next 2 years. We have accrued the discounted present value of these required additional payments ($11.4 million) and recorded this amount plus the upfront payment in "Deposits on properties under option or contract" on our December 31, 2006 Consolidated Balance Sheet. Additionally, the upfront payment of $37.5 million is recorded on our December 31, 2006 Consolidated Statement of Cash Flow – Investing Activities.

**Fair Value of Financial Instruments**

| | December 31, 2006 | | 2005 | |
|---|---|---|---|---|
| (In Thousands) | Carrying Amount | Estimated Fair Value | Carrying Amount | Estimated Fair Value |
| 7.5% Senior Subordinated Notes due 2013 | **$ 223,786** | **$ 227,250** | $223,591 | $228,375 |
| 7.5% Senior Subordinated Notes due 2015 | **150,000** | **152,250** | 150,000 | 152,250 |
| Senior Bank Loan | **134,000** | **134,000** | — | — |

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 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 13. Condensed Consolidating Financial Information

Since December 29, 2003, Denbury Resources Inc. and Denbury Onshore, LLC are co-obligors of our subordinated debt. Our subordinated debt is fully and unconditionally guaranteed jointly and severally by all of Denbury Resources Inc.'s subsidiaries other than minor subsidiaries. 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 significant subsidiaries:

**Condensed Consolidating Balance Sheets**

| (In Thousands) | Denbury Resources Inc. (Parent and Co-obligor) | Denbury Onshore, LLC (Issuer and Co-obligor) | Guarantor Subsidiaries | Eliminations | Denbury Resources, Inc. Consolidated |
|---|---|---|---|---|---|
| | December 31, 2006 | | | | |
| ASSETS | | | | | |
| Current assets | **$ 392,372** | **$ 180,476** | **$ 3,662** | **$ (393,241)** | **$ 183,269** |
| Property and equipment | **—** | **1,879,742** | **26** | **—** | **1,879,768** |
| Investment in subsidiaries (equity method) | **709,611** | **—** | **709,020** | **(1,407,991)** | **10,640** |
| Other assets | **154,076** | **64,391** | **154** | **(152,461)** | **66,160** |
| Total assets | **$1,256,059** | **$2,124,609** | **$712,862** | **$(1,953,693)** | **$2,139,837** |
| LIABILITIES AND STOCKHOLDERS' EQUITY | | | | | |
| Current liabilities | **$ —** | **$ 590,602** | **$ 3,037** | **$ (393,241)** | **$ 200,398** |
| Long-term liabilities | **150,000** | **835,627** | **214** | **(152,461)** | **833,380** |
| Stockholders' equity | **1,106,059** | **698,380** | **709,611** | **(1,407,991)** | **1,106,059** |
| Total liabilties and stockholders' equity | **$1,256,059** | **$2,124,609** | **$712,862** | **$(1,953,693)** | **$2,139,837** |

| (In Thousands) | Denbury Resources Inc. (Parent and Co-obligor) | Denbury Onshore, LLC (Issuer and Co-obligor) | Guarantor Subsidiaries | Eliminations | Denbury Resources, Inc. Consolidated |
|---|---|---|---|---|---|
| | December 31, 2005 | | | | |
| ASSETS | | | | | |
| Current assets | $ 222,858 | $ 297,575 | $ 2,577 | $ (223,827) | $ 299,183 |
| Property and equipment | — | 1,155,923 | 47 | — | 1,155,970 |
| Investment in subsidiaries (equity method) | 506,862 | — | 505,540 | (1,001,573) | 10,829 |
| Other assets | 154,288 | 37,120 | 169 | (152,490) | 39,087 |
| Total assets | $ 884,008 | $ 1,490,618 | $508,333 | $(1,377,890) | $1,505,069 |
| LIABILITIES AND STOCKHOLDERS' EQUITY | | | | | |
| Current liabilities | $ 346 | $ 376,194 | $ 1,351 | $ (223,827) | $ 154,064 |
| Long-term liabilities | 150,000 | 619,713 | 120 | (152,490) | 617,343 |
| Stockholders' equity | 733,662 | 494,711 | 506,862 | (1,001,573) | 733,662 |
| Total liabilities and stockholders' equity | $ 884,008 | $ 1,490,618 | $508,333 | $(1,377,890) | $1,505,069 |

**Condensed Consolidating Statements of Operations**

| (In Thousands) | Denbury Resources Inc. (Parent and Co-obligor) | Denbury Onshore, LLC (Issuer and Co-obligor) | Guarantor Subsidiaries | Eliminations | Denbury Resources, Inc. Consolidated |
|---|---|---|---|---|---|
| | Year Ended December 31, 2006 | | | | |
| **Revenues** | **$ 11,219** | **$ 731,516** | **$ 20** | **$ (11,219)** | **$ 731,536** |
| **Expenses** | **11,581** | **400,657** | **1,719** | **(11,219)** | **402,738** |
| **Income before the following:** | **(362)** | **330,859** | **(1,699)** | **—** | **328,798** |
| **Equity in net earnings of subsidiaries** | **202,749** | **—** | **204,445** | **(406,418)** | **776** |
| **Income before income taxes** | **202,387** | **330,859** | **202,746** | **(406,418)** | **329,574** |
| **Income tax provision (benefit)** | **(70)** | **127,189** | **(2)** | **—** | **127,117** |
| **Net income** | **$ 202,457** | **$ 203,670** | **$ 202,748** | **$ (406,418)** | **$ 202,457** |

| (In Thousands) | Denbury Resources Inc. (Parent and Co-obligor) | Denbury Onshore, LLC (Issuer and Co-obligor) | Guarantor Subsidiaries | Eliminations | Denbury Resources, Inc. Consolidated |
|---|---|---|---|---|---|
| | Year Ended December 31, 2005 | | | | |
| Revenues | $ 313 | $ 560,079 | $ — | $ — | $ 560,392 |
| Expenses | 485 | 310,974 | 1,206 | — | 312,665 |
| Income before the following: | (172) | 249,105 | (1,206) | — | 247,727 |
| Equity in net earnings of subsidiaries | 166,576 | — | 167,378 | (333,640) | 314 |
| Income before income taxes | 166,404 | 249,105 | 166,172 | (333,640) | 248,041 |
| Income tax provision (benefit) | (67) | 82,041 | (404) | — | 81,570 |
| Net income | $ 166,471 | $ 167,064 | $ 166,576 | $ (333,640) | $ 166,471 |

| (In Thousands) | Denbury Resources Inc. (Parent and Co-obligor) | Denbury Onshore, LLC (Issuer and Co-obligor) | Guarantor Subsidiaries | Eliminations | Denbury Resources, Inc. Consolidated |
|---|---|---|---|---|---|
| | Year Ended December 31, 2004 | | | | |
| Revenues | $ — | $ 320,328 | $ 62,644 | $ — | $ 382,972 |
| Expenses | 171 | 222,988 | 37,837 | — | 260,996 |
| Income before the following: | (171) | 97,340 | 24,807 | — | 121,976 |
| Equity in net earnings of subsidiaries | 82,554 | — | 67,122 | (149,812) | (136) |
| Income before income taxes | 82,383 | 97,340 | 91,929 | (149,812) | 121,840 |
| Income tax provision (benefit) | (65) | 30,082 | 9,375 | — | 39,392 |
| Net income | $ 82,448 | $ 67,258 | $ 82,554 | $ (149,812) | $ 82,448 |

**Condensed Consolidating Statements of Cash Flows**

| (In Thousands) | Denbury Resources Inc. (Parent and Co-obligor) | Denbury Onshore, LLC (Issuer and Co-obligor) | Guarantor Subsidiaries | Eliminations | Denbury Resources, Inc. Consolidated |
|---|---|---|---|---|---|
| | Year Ended December 31, 2006 | | | | |
| Cash flow from operations | **$ —** | **$ 460,841** | **$ 969** | **$ —** | **$ 461,810** |
| Cash flow from investing activities | **(150,864)** | **(856,625)** | **(2)** | **150,864** | **(856,627)** |
| Cash flow from financing activities | **150,864** | **283,601** | **—** | **(150,864)** | **283,601** |
| Net increase (decrease) in cash | **—** | **(112,183)** | **967** | **—** | **(111,216)** |
| Cash, beginning of period | **1** | **164,408** | **680** | **—** | **165,089** |
| Cash, end of period | **$ 1** | **$ 52,225** | **$ 1,647** | **$ —** | **$ 53,873** |

| (In Thousands) | Denbury Resources Inc. (Parent and Co-obligor) | Denbury Onshore, LLC (Issuer and Co-obligor) | Guarantor Subsidiaries | Eliminations | Denbury Resources, Inc. Consolidated |
|---|---|---|---|---|---|
| | Year Ended December 31, 2005 | | | | |
| Cash flow from operations | $ (5,298) | $ 365,714 | $ 544 | $ — | $ 360,960 |
| Cash flow from investing activities | (150,000) | (383,666) | (21) | 150,000 | (383,687) |
| Cash flow from financing activities | 155,298 | 149,479 | — | (150,000) | 154,777 |
| Net increase in cash | — | 131,527 | 523 | — | 132,050 |
| Cash, beginning of period | 1 | 32,881 | 157 | — | 33,039 |
| Cash, end of period | $ 1 | $ 164,408 | $ 680 | $ — | $ 165,089 |

| (In Thousands) | Denbury Resources Inc. (Parent and Co-obligor) | Denbury Onshore, LLC (Issuer and Co-obligor) | Guarantor Subsidiaries | Eliminations | Denbury Resources, Inc. Consolidated |
|---|---|---|---|---|---|
| | Year Ended December 31, 2004 | | | | |
| Cash flow from operations | $ (9,192) | $ 331,123 | $(153,279) | $ — | $ 168,652 |
| Cash flow from investing activities | — | (246,973) | 153,423 | — | (93,550) |
| Cash flow from financing activities | 9,192 | (75,443) | — | — | (66,251) |
| Net increase in cash | — | 8,707 | 144 | — | 8,851 |
| Cash, beginning of period | 1 | 24,174 | 13 | — | 24,188 |
| Cash, end of period | $ 1 | $ 32,881 | $ 157 | $ — | $ 33,039 |

## Note 14. Supplemental Oil and Natural Gas Disclosures (unaudited)

**Costs Incurred**

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

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

| (In Thousands) | Year Ended December 31, 2006 | 2005 | 2004 |
|---|---|---|---|
| Property acquisitions: | | | |
| Proved | **$ 137,891** | $ 63,509 | $ 22,271 |
| Unevaluated | **205,506** | 32,874 | 3,459 |
| Exploration | **43,564** | 45,652 | 23,987 |
| Development | **440,827** | 237,201 | 128,351 |
| Asset retirement obligations | **12,803** | 4,559 | 3,174 |
| Total costs incurred [1] | **$840,591** | $383,795 | $181,242 |

*(1) Capitalized general and administrative costs that directly relate to exploration and development activities were $7.6 million, $5.1 million, and $5.1 million for the years ended December 31, 2006, 2005 and 2004, respectively.*

**Oil and Natural Gas Operating Results**

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

| (In Thousands, Except Per BOE data) | Year Ended December 31, 2006 | 2005 | 2004 |
|---|---|---|---|
| Oil, natural gas and related product sales | **$ 716,557** | $549,055 | $444,777 |
| Loss on effective hedge contracts | **—** | — | (70,469) |
| Total revenues | **716,557** | 549,055 | 374,308 |
| Lease operating costs | **167,271** | 108,550 | 87,107 |
| Production taxes and marketing expenses | **36,351** | 27,582 | 18,737 |
| Depletion, depreciation and amortization | **135,269** | 90,631 | 90,913 |
| $CO_2$ depletion, depreciation and amortization [1] | **6,281** | 3,894 | 3,405 |
| Commodity derivative expense (income) | **(19,828)** | 28,962 | 15,358 |
| Net operating income | **391,213** | 289,436 | 158,788 |
| Income tax provision | **151,008** | 95,224 | 51,289 |
| Results of operations from oil and natural gas producing activities | **$240,205** | $ 194,212 | $ 107,499 |
| Depletion, depreciation and amortization per BOE | **$ 10.54** | $ 8.69 | $ 7.82 |

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

**Oil and Natural Gas Reserves**

Net proved oil and natural gas reserve estimates for all years presented were prepared by DeGolyer and MacNaughton, independent petroleum engineers located in Dallas, Texas. The reserves were prepared in accordance with guidelines established by the Securities and Exchange Commission and, accordingly, were based on existing economic and operating conditions. Oil and natural gas prices in effect as of the reserve report date were used without any escalation. (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 with no escalation.

We have a corporate policy whereby we do not book proved undeveloped reserves until we have committed to perform the required development operations, the majority of which we generally expect to commence within the next few years.

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, | | | | | |
|---|---|---|---|---|---|---|
| | 2006 | | 2005 | | 2004 | |
| | Oil (MBBL) | Gas (MMCF) | Oil (MBBL) | Gas (MMCF) | Oil (MBBL) | Gas (MMCF) |
| Balance at beginning of year | **106,173** | **278,367** | 101,287 | 168,484 | 91,266 | 221,887 |
| Revisions of previous estimates | **4,351** | **(22,279)** | (3,613) | (12,047) | (3,271) | 2,898 |
| Revisions due to price changes | **(2)** | **(3,116)** | 872 | 1,268 | 492 | 25 |
| Extensions and discoveries | **4,587** | **65,582** | 1,214 | 117,512 | 1,575 | 61,158 |
| Improved recovery [1] | **5,044** | **—** | 13,276 | — | 18,863 | — |
| Production | **(8,372)** | **(30,322)** | (7,305) | (21,424) | (7,044) | (30,094) |
| Acquisition of minerals in place | **14,424** | **643** | 442 | 24,574 | 429 | 5,304 |
| Sales of minerals in place | **(20)** | **(49)** | — | — | (1,023) | (92,694) |
| Balance at end of year | **126,185** | **288,826** | 106,173 | 278,367 | 101,287 | 168,484 |
| Proved Developed Reserves: | | | | | | |
| Balance at beginning of year | **59,640** | **151,681** | 55,998 | 94,573 | 53,804 | 144,750 |
| Balance at end of year | **83,703** | **176,648** | 59,640 | 151,681 | 55,998 | 94,573 |

*(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.*

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

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

Under the Standardized Measure, future cash inflows were estimated by applying 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 proven reserves as reductions in oil and gas prices can causes 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 year-end prices were used in the Standardized Measure. These prices were adjusted by field to arrive at the appropriate corporate net price.

| | December 31, | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| Oil (NYMEX) | **$ 61.05** | $ 61.04 | $43.45 |
| Natural Gas (Henry Hub) | **5.63** | 10.08 | 6.18 |

Future cash inflows were reduced by estimated future production, development and abandonment costs based on year-end costs 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) | 2006 | 2005 | 2004 |
| Future cash inflows | **$ 8,185,682** | $ 8,197,957 | $ 4,742,276 |
| Future production costs | **(2,697,206)** | (2,069,015) | (1,509,280) |
| Future development costs | **(565,488)** | (525,877) | (340,879) |
| Future net cash flows before taxes | **4,922,988** | 5,603,065 | 2,892,117 |
| Future income taxes | **(1,519,179)** | (1,944,430) | (906,221) |
| Future net cash flows | **3,403,809** | 3,658,635 | 1,985,896 |
| 10% annual discount for estimated timing of cash flows | **(1,566,468)** | (1,574,186) | (856,700) |
| Standardized measure of discounted future net cash flows | **$ 1,837,341** | $ 2,084,449 | $ 1,129,196 |

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

| | Year Ended December 31, | | |
|---|---|---|---|
| (In Thousands) | 2006 | 2005 | 2004 |
| Beginning of year | **$2,084,449** | $ 1,129,196 | $1,124,127 |
| Sales of oil and natural gas produced, net of production costs | **(512,935)** | (412,923) | (339,250) |
| Net changes in sales prices | **(552,772)** | 1,261,231 | 352,830 |
| Extensions and discoveries, less applicable future development and production costs | **124,787** | 461,936 | 151,014 |
| Improved recovery [1] | **117,342** | 204,116 | 190,033 |
| Previously estimated development costs incurred | **124,207** | 110,424 | 55,091 |
| Revisions of previous estimates, including revised estimates of development costs, reserves and rates of production | **(324,608)** | (261,730) | (197,959) |
| Accretion of discount | **321,548** | 164,329 | 156,637 |
| Acquisition of minerals in place | **182,374** | 44,807 | 9,003 |
| Sales of minerals in place | **(222)** | — | (300,481) |
| Net change in income taxes | **273,171** | (616,937) | (71,849) |
| End of year | **$ 1,837,341** | $2,084,449 | $1,129,196 |

*(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 5.5 Tcf at December 31, 2006 (includes 210.5 Bcf of reserves dedicated to three volumetric production payments with Genesis), 4.6 Tcf at December 31, 2005 (includes 237.1 Bcf of reserves dedicated to three volumetric production payments with Genesis), and 2.7 Tcf at December 31, 2004 (includes 178.7 Bcf of reserves dedicated to two 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 15. Unaudited Quarterly Information

| In Thousands, Except Per Share Amounts | March 31 | June 30 | September 30 | December 31 |
|---|---|---|---|---|
| 2006 | | | | |
| Revenues | **$ 178,906** | **$ 193,247** | **$ 192,044** | **$ 167,339** |
| Expenses | **107,398** | **119,978** | **97,237** | **78,125** |
| Net income | **43,778** | **44,262** | **59,294** | **55,123** |
| Net income per share: | | | | |
| Basic | **0.39** | **0.38** | **0.50** | **0.46** |
| Diluted | **0.37** | **0.36** | **0.48** | **0.45** |
| Cash flow from operations | **102,512** | **106,417** | **135,365** | **117,516** |
| Cash flow used for investing activities [1] | **(347,684)** | **(205,495)** | **(143,349)** | **(160,099)** |
| Cash flow provided by financing activities [2] | **110,067** | **99,906** | **6,096** | **67,532** |
| 2005 | | | | |
| Revenues | $ 113,362 | $ 127,983 | $ 141,858 | $ 177,189 |
| Expenses | 69,754 | 67,491 | 83,249 | 92,171 |
| Net income | 30,067 | 40,672 | 38,546 | 57,186 |
| Net income per share: | | | | |
| Basic | 0.27 | 0.37 | 0.34 | 0.51 |
| Diluted | 0.26 | 0.34 | 0.32 | 0.48 |
| Cash flow from operations | 66,629 | 88,385 | 76,287 | 129,659 |
| Cash flow used for investing activities [3] | (59,614) | (117,530) | (75,840) | (130,703) |
| Cash flow provided by financing activities [4] | 2,688 | 11,719 | 11,227 | 129,143 |

*(1) In January 2006, we acquired three oil properties for approximately $250 million (including the $25 million of earnest money paid in the fourth quarter of 2005). In May 2006, we acquired an oil property for $50 million, plus a reversionary interest. In November 2006, we entered into an agreement for the option to purchase an oil property for an upfront payment of $37.5 million, plus required additional payments totaling $12.5 million. (See Note 2. Acquisitions and Divestitures.)*

*(2) In April, we sold $125 million (net to Denbury) of common stock in a public offering (see Note 8. Stockholders' Equity – Stock Issuance). We had net borrowings of $100 million and $64 million in the first and fourth quarters of 2006, respectively, and net repayments of $30 million in the second quarter of 2006, all under our senior bank loan.*

*(3) In November 2005, we made a $25 million deposit of earnest money associated with a pending acquisition of oil properties (see Note 2. Acquisitions and Divestitures).*

*(4) In December 2005, we issued $150 million of 7.5% Senior Subordinated Notes due 2015 (see Note 6. Notes Payable and Long-Term Indebtedness).*

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

There have been no changes in accountants nor any disagreements with accountants.

## Item 9A. Controls and Procedures

### Disclosure Controls and Procedures

We maintain disclosure controls and procedures and internal controls designed to ensure that information required to be disclosed in our filings under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. Our chief executive officer and chief financial officer have evaluated our disclosure controls and procedures as of the end of the period covered by this annual report on Form 10-K and have determined that such disclosure controls and procedures are effective as of December 31, 2006, in ensuring that material information required to be disclosed in this annual report is accumulated and communicated to them and our management to allow timely decisions regarding required disclosure.

### Changes in Internal Control over Financial Reporting

During 2005 and 2006, information was reported on our whistleblower hotline regarding misconduct by oilfield vendors and certain employees, including alleged improper billings and payments by certain vendors to, or on behalf of employees, misuse of Company property, services and operational information by employees, and the failure by certain employees to properly report transactions with the Company. During 2005 and 2006, at the direction of the Audit Committee of our Board of Directors, and in conjunction with outside counsel retained by the Audit Committee, investigations were undertaken regarding these matters. These investigations are substantially complete. As a result of our investigations, we have dismissed eight employees, taken disciplinary action against another employee, and terminated all future business with certain vendors. The estimated amount of improper vendor billings and payments and misuse of Company property and services is inconsequential to our previously issued financial statements and to the financial statements contained in this report on Form 10-K. We further believe that these matters have not, and will not, materially adversely affect our financial condition, results of operations or business. We believe that our whistleblower hotline was effective in alerting us to improper vendor and employee conduct and allowing us to remedy the matter.

Controls and policies in place to prevent these occurrences were overridden by employee misconduct in the vendor approval and payment process and in adherence to the Company's Code of Business Conduct and Ethics. As a result of our investigation, we have, and are continuing, to implement certain improvements to strengthen our internal controls (see also Item 9A. "Controls and Procedures"— "Disclosure Controls and Procedures" contained in our 2005 Form 10-K for further information) and to improve our management practices and policies. Various management changes have been made, combined with an emphasis upon both strengthening our internal controls and improving management oversight and enforcement of Company policies and procedures at the field level.

## 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 15, 2007, (Annual Meeting) and is incorporated herein by reference.

### Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 and the rules thereunder require the Company's executive officers and directors, and persons who beneficially own more than ten percent (10%) of a registered class of the Company's equity securities, to file reports of ownership and changes in ownership with the Securities and Exchange Commission and exchanges and to furnish the Company with copies. Based solely on its review of the copies of such forms received by it, or written representations from such persons, the Company is aware of one filing that was not timely made by Mr. Gareth Roberts, President and CEO, who failed to timely file a Form 5 reporting the transfer of shares as a gift to his minor children.

### Code of Ethics

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

## Item 11. Executive Compensation

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

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

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

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

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

## Item 14. Principal Accountant Fees and Services

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

## Item 15. Exhibits and Financial Statement Schedules

*Financial Statements and Schedules.* Financial statements and schedules filed as a part of this report are presented on page 52. 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(a) | Agreement and Plan of Merger to Form Holding Company, dated as of December 22, 2003, but effective December 29, 2003, at 9:00 a.m. EST, by and among the Registrant, the Predecessor and Denbury Onshore, LLC (incorporated by reference as Exhibit 2.1 of our Form 8-K filed December 29, 2003). |
| 2(b) | Stock Purchase Agreement made as of July 19, 2004, between Denbury Resources Inc. and Newfield Exploration Company (incorporated by reference as Exhibit 2.14 of our Form 8-K filed August 4, 2004). |
| 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, 2005 (incorporated by reference as Exhibit 3(a) of our Form 10-Q filed November 8, 2005). |
| 3(c) | 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 $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(b) | 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) to our Registration Statement No. 333-105233-04 on Form S-4, filed May 14, 2003). |
| 4(c) | First Supplemental 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). |
| 10(a) | Purchase and Sale Agreement dated as of November 9, 2005, by and among Merit Management Partners I, L. P., Merit Energy Partners III, L.P. and Merit Energy Partners D-III, L.P., and Denbury Onshore, LLC. (incorporated by reference as Exhibit 10.1 of our Form 8-K filed February 3, 2006). |
| 10(b) | 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, 2006 (incorporated by reference as Exhibit 10.1 of our Form 8-K filed September 19, 2006). |
| 10(c) * | Amendment for Increased Commitment from $150 million to $250 million to Sixth Amended and Restated Credit Agreement among Denbury Onshore, LLC, as Borrower, Denbury Resources Inc, as Parent Guarantor, Bank One, N.A. as Administrative Agent, and certain other financial institutions dated as of December 22, 2006. |
| 10(d) ** | Denbury Resources Inc. Amended and Restated Stock Option Plan (incorporated by reference as Exhibit 99 of our Registration Statement No. 333-106253 on Form S-8, filed June 18, 2003). |
| 10(e) ** | Denbury Resources Inc. Stock Purchase Plan, as amended (incorporated by reference as Exhibit 4(g) of our Registration Statement on Form S-8, No. 333-1006, filed February 2, 1996, with amendments incorporated by reference as exhibits of our Registration Statements on Forms S-8, No. 333-70485, filed January 12, 1999, No. 333-39218, filed June 13, 2000 and No. 333-90398, filed June 13, 2002). |

| Exhibit No. | Exhibit |
|---|---|
| 10(f) ** | 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(g) ** | 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, 2005). |
| 10(h) ** | Denbury Resources Severance Protection Plan, dated December 6, 2000 (incorporated by reference as Exhibit 10(f) of our Form 10-K for the year ended December 31, 2000). |
| 10(i) ** | Denbury Resources Inc. 2004 Omnibus Stock and Incentive Plan as amended (incorporated by reference as Exhibit 10(g) of our Form 10-K for the year ended December 31, 2004). |
| 10(j) ** | Description of cash bonus compensation arrangements for employees and officers (incorporated by reference as exhibit 10 (l) of our Form 10-K for the year ended December 31, 2005). |
| 10(k)* ** | Description of equity and other long-term award grant practices for employees and officers. |
| 10(l)* ** | Description of non-employee directors' compensation arrangements. |
| 10(m) ** | 2004 form of restricted stock award that vests 20% per annum, for grants to officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(k) of our Form 10-K for the year ended December 31, 2004). |
| 10(n) ** | 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(o) ** | 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(p) ** | 2005 form of incentive stock option agreement that vests 25% per annum, for grants to new employees and officers on their hire date pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(n) of our Form 10-K for the year ended December 31, 2004). |
| 10(q) ** | 2005 form of incentive stock option agreement 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(o) of our From 10-K for the year ended December 31, 2004). |
| 10(r) ** | 2005 form of non-qualified stock option agreement that vests 25% per annum, for grants to new employees and officers on their hire date pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(p) of our Form 10-K for the year ended December 31, 2004). |
| 10(s) ** | 2005 form of non-qualified stock option agreement that cliff vests 100% four years from the date of grant, for grants to employees, officers and directors pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10(q) of our Form 10-K for the year ended December 31, 2004). |
| 10(t) ** | 2006 form of stock appreciation rights agreement 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(v) of our Form 10-K for the year ended December 31, 2005). |
| 10(u) ** | 2006 form of stock appreciation rights agreement that vests 100% four years from the date of grant, for grants to employees and officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10 (w) of our Form 10-K for the year ended December 31, 2005). |

| Exhibit No. | Exhibit |
|---|---|
| 10(v) ** | 2006 form of stock appreciation rights agreement that cliff vests 100% four years from the date of grant, for grants to directors pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10 (x) of our Form 10-K for the year ended December 31, 2005). |
| 10(w) ** | 2006 form of restricted stock award that vests 25% per annum, for grants to new employees and officers on their hire date pursuant to 2004 Omnibus and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10 (y) of our Form 10-K for the year ended December 31, 2005). |
| 10(x) ** | 2006 form of restricted stock award that cliff vests 100% four years from the date of grant for grants to employees and officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. (incorporated by reference as Exhibit 10 (z) of our Form 10-K for the year ended December 31, 2005). |
| 10(y)* ** | 2007 form of restricted stock award to officers that cliff vests on March 31, 2010 pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. |
| 10(z)* ** | 2007 form of performance share awards to officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc. |
| 10(aa)* ** | 2007 form of restricted stock award to directors that cliff vests after three years pursuant to 2004 Omnibus Stock and Incentive Plan. |
| 10(bb) ** | 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(cc) ** | Form of deferred payment cash award that vests 25% per annum, for grants to new employees and officers on their date of hire (incorporated by reference as Exhibit 10(aa) of our Form 10-K for the year ended December 31, 2005). |
| 16 | Letter from Deloitte & Touche LLP to the Securities and Exchange Commission dated May 24, 2005, regarding changes in certifying accountant, pursuant to Item 304(a)(3) of Regulation S-K (incorporated by reference as Exhibit 16.1 of our Form 8-K/A filed May 24, 2005). |
| 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, 2006, on oil and gas reserves (SEC Case) dated February 14, 2007. |

* *Filed herewith.*

** *Compensation arrangements.*

*Copies of the above exhibits not contained herein are available to any security holder upon written request to the Secretary, Denbury Resources Inc., 5100 Tennyson Pkwy., Ste 1200, Plano, TX 75204.*

## 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/ Phil Rykhoek February 28, 2007

Phil Rykhoek
Sr. Vice President and Chief Financial Officer

/s/ Mark C. Allen February 28, 2007

Mark C. Allen
Vice President and Chief Accounting Officer

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

/s/ Gareth Roberts February 28, 2007

Gareth Roberts
Director, President and Chief Executive Officer
(Principal Executive Officer)

/s/ Phil Rykhoek February 28, 2007

Phil Rykhoek
Sr. Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ Mark C. Allen February 28, 2007

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

/s/ Ron Greene February 28, 2007

Ron Greene
Director

/s/ David I. Heather February 28, 2007

David I. Heather
Director

/s/ Randy Stein February 28, 2007

Randy Stein
Director

/s/ Wieland Wettstein February 28, 2007

Wieland Wettstein
Director

/s/ Greg McMichael February 28, 2007

Greg McMichael
Director

/s/ Donald Wolf February 28, 2007

Donald Wolf
Director

## Exhibit 31 (a)

**Certification Under Section 302 of the Sarbanes-Oxley Act of 2002**

I, Gareth Roberts, 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/ Gareth Roberts February 28, 2007

Gareth Roberts
President and Chief Executive Officer

## Exhibit 31(b)

**Certification Under Section 302 of the Sarbanes-Oxley Act of 2002**

I, Phil Rykhoek, certify that:

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

/s/ Phil Rykhoek February 28, 2007

Phil Rykhoek
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, 2006 (the Report) of Denbury Resources Inc. (Denbury) as filed with the Securities and Exchange Commission on February 28, 2007, 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/ Gareth Roberts February 28, 2007

Gareth Roberts
President and Chief Executive Officer

/s/ Phil Rykhoek February 28, 2007

Phil Rykhoek
Sr. Vice President and Chief Financial Officer

## Board of Directors

**Ronald G. Greene**
Chairman of the Board
Principal
Tortuga Investment Corp.
Calgary Alberta

**David I. Heather**
Director
The Scotia Group
Dallas, Texas

**Greg McMichael**
Independent Consultant
Denver, Colorado

**Gareth Roberts**
President & C.E.O.
Denbury Resources Inc.
Dallas, Texas

**Randy Stein**
Independent Consultant
Denver, Colorado

**Wieland F. Wettstein**
President
Finex Financial
Corporation, Ltd.
Calgary Alberta

**Don Wolf**
President & C.E.O.
Aspect Energy
Denver, Colorado

## Officers

**Gareth Roberts**
President & C.E.O.

**Tracy Evans**
Senior Vice President
Reservoir Engineering

**Phil Rykhoek**
Senior Vice President &
Chief Financial Officer

**Robert Cornelius**
Senior Vice President
Operations

**Mark Allen**
Vice President & Chief
Accounting Officer

**Dan Cole**
Vice President
Marketing

**Ray Dubuisson**
Vice President
Land

**Jim Sinclair**
Vice President
Exploration and
Geosciences

## Corporate Headquarters

Denbury Resources Inc.
5100 Tennyson Pkwy, Ste. 1200
Plano, Texas 75024
T: 972.673.2000
F: 972.673.2150

## Register and Transfer Agent

American Stock Transfer
and Trust Company
New York, NY

## Legal Counsel

Baker & Hostetler LLP

## Annual Meeting

The annual meeting of stockholders will be held on May 15, 2007, at 3:00 P.M., local time, at the Marriott at Legacy Town Center Hotel located at:
7120 Dallas Parkway
Plano, Texas 75024

All stockholders are encouraged to attend, but if unable should complete and return the proxy card.

## Bankers

JP Morgan (Agent)

## Auditors

PricewaterhouseCoopers LLP

## Evaluation Engineers

DeGolyer & MacNaughton

## Stock Exchange

New York Stock Exchange
Trading Symbol: DNR

## For Further Information

Contact Gareth Roberts or Phil Rykhoek at Corporate Headquarters. We have listed on our website at www.denbury.com, our corporate governance guidelines, as well as the charters for our nominating/governance committee, our compensation committee, and our audit committee. 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 e-mail to secretary@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 to Laurie Burkes at the Company's headquarters. This report can also be accessed at our website, www.denbury.com.

During 2006, the Company submitted its written affirmation and annual Chief Executive Officer certification for 2005 pursuant to Section 303A of the New York Stock Exchange regulations without qualifications.

The cover and narrative section of this annual report are printed on Centura dull text and cover, which contain 10% post-consumer-recovered-fiber content, and is FSC certified. The financial section is printed on Durotone and is not FSC certified.

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