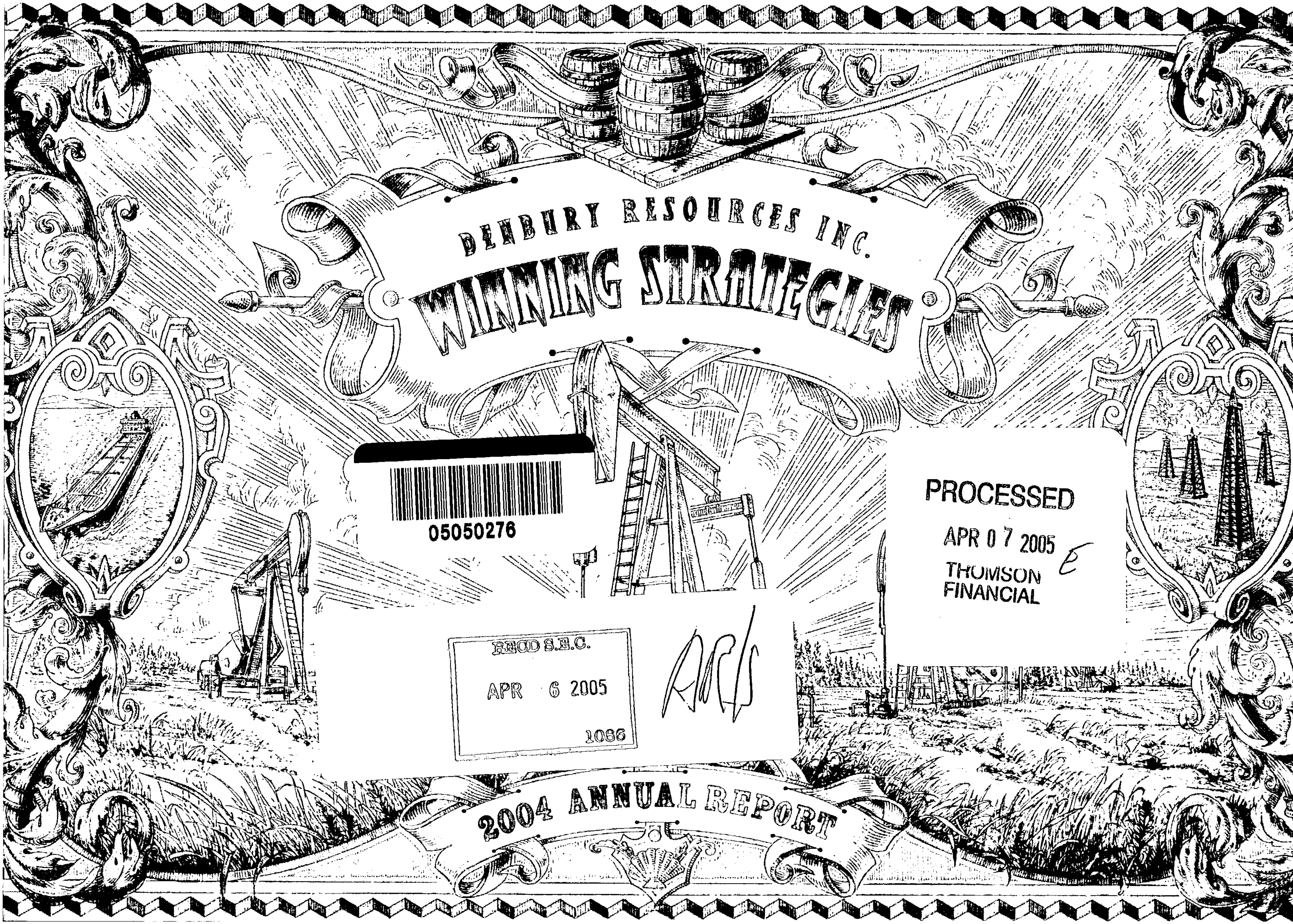

DENBURY RESOURCES INC.
WINNING STRATEGIES
2004 ANNUAL REPORT

Over the past five years Denbury has developed a unique strategy in our industry using CO_2 tertiary flooding which we believe will provide long-term organic production and reserve growth. If the name of the game is to provide the highest rates of return to shareholders, then we feel that our plan will ultimately separate us from our peer group. We believe we have a winning strategy.

FINANCIAL HIGHLIGHTS

AMOUNTS IN THOUSANDS, UNLESS OTHERWISE NOTED	YEAR ENDED DECEMBER 31, 2004	2003	2002	2001	2000	AVERAGE ANNUAL GROWTH[1]
PRODUCTION (DAILY)						
Oil (Bbls)	19,247	18,894	18,833	16,978	15,219	6%
Natural gas (Mcf)	82,224	94,858	100,443	85,238	37,078	22%
BOE (6:1)	32,951	34,704	35,573	31,185	21,399	11%
REVENUES	382,972	333,014	285,152	285,111	181,651	20%
UNIT SALES PRICE (EXCLUDING HEDGES)						
Oil (per Bbl)	36.46	27.47	22.36	21.34	25.89	9%
Natural gas (per Mcf)	6.24	5.66	3.31	4.12	4.45	9%
UNIT SALES PRICE (INCLUDING HEDGES)						
Oil (per Bbl)	27.36	24.52	22.27	21.65	23.50	4%
Natural gas (per Mcf)	5.57	4.45	3.35	4.66	3.57	12%
CASH FLOW FROM OPERATIONS	168,652	197,615	159,600	185,047	95,972	15%
NET INCOME [2]	82,448	56,553	46,795	56,550	142,227	(13%)
AVERAGE COMMON SHARES OUTSTANDING						
Basic	54,871	53,881	53,243	49,325	45,823	5%
Diluted	57,301	55,464	54,365	50,361	46,352	5%
NET INCOME PER SHARE						
Basic	1.50	1.05	0.88	1.15	3.10	(17%)
Diluted	1.44	1.02	0.86	1.12	3.07	(17%)
OIL AND GAS CAPITAL INVESTMENTS	178,070	158,444	155,637	327,175	134,021	7%
CO_2 CAPITAL INVESTMENTS	50,265	22,673	16,445	45,555	–	–
TOTAL ASSETS	992,706	982,621	895,292	789,988	457,379	21%
LONG-TERM LIABILITIES	368,128	434,845	432,616	360,882	202,428	16%
STOCKHOLDERS' EQUITY [3]	541,672	421,202	366,797	349,168	216,165	26%
PROVED RESERVES						
Oil (MBbls)	101,287	91,266	97,203	76,490	70,667	9%
Natural gas (MMcf)	168,484	221,887	200,947	198,277	100,550	14%
MBOE (6:1)	129,369	128,247	130,694	109,536	87,425	10%
Discounted future cash flow before tax–10%	1,643,289	1,566,371	1,426,220	574,328	1,158,969	9%
Standardized measure of discounted future net cash flows after tax	1,129,196	1,124,127	1,028,976	505,795	841,299	8%
PER BOE DATA (6:1)						
Oil and natural gas revenues	36.88	30.43	21.17	22.88	26.13	9%
Gain (loss) on settlements of derivative contracts	(7.01)	(4.91)	0.07	1.64	(3.23)	21%
Lease operating expenses	(7.22)	(7.06)	(5.48)	(4.84)	(4.94)	10%
Production taxes and marketing expenses	(1.55)	(1.17)	(0.92)	(0.96)	(1.02)	11%
Production netback	21.10	17.29	14.84	18.72	16.94	6%
Operating margin from CO_2 industrial sales	0.41	0.51	0.48	0.38	–	–
General and administrative expense	(1.78)	(1.20)	(0.96)	(0.89)	(1.09)	13%
Net cash interest expense	(1.34)	(1.61)	(1.73)	(1.74)	(1.54)	(3%)
Current income taxes and other	(1.78)	(0.01)	0.04	(0.06)	(0.07)	–
Changes in assets and liabilities	(2.63)	0.62	(0.38)	(0.15)	(1.99)	7%
CASH FLOW FROM OPERATIONS	13.98	15.60	12.29	16.26	12.25	3%

[1] Four-year compounded annual growth rate computed using 2000 as a base year.

[2] 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" (see Note 4 to the Consolidated Financial Statements). In 2000, we recorded a deferred income tax benefit of $67.9 million related to the reversal of the valuation allowance on our net deferred assets at December 31, 2000.

[3] 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.

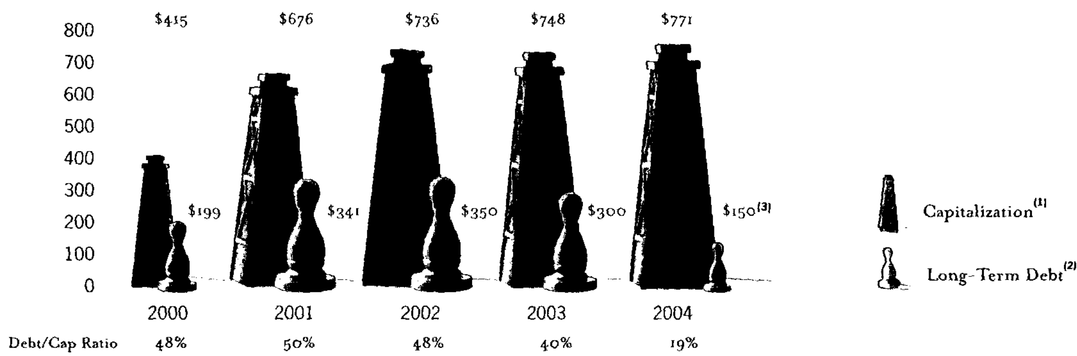
See page 24 regarding cautionary notes about forward-looking statements and unproved reserves contained herein.

Message to Shareholders

We had perhaps our best year ever in 2004. We were able to execute and achieve several important goals, in addition to posting strong financial results. We have entitled this year's annual report "Winning Strategies," and in keeping with that theme, we continued with our strategy during 2004 and will continue to do so in the future, anticipating that this will produce winning results for our shareholders.

The anchor of our game plan is our CO_2 play. This play provides us with a low risk way to achieve our ultimate goal of consistent, strong, organic production growth. It allowed us to divest of our offshore division, which in turn lowered our debt and gave us the ability to accelerate our capital investments in the CO_2 play to the extent practical and economical. With our CO_2 play underpinning our entire program, we anticipate that we will be able to achieve double digit organic production growth over the next five years.

Debt to Capital Analysis



[1] Excludes accumulated other comprehensive income (loss).
[2] Principal amount of sub-debt; excludes discount.
[3] Net Debt: $225 million of sub-debt less $75 million of excess cash and short-term investments.

2004 Accomplishments

We achieved numerous successes during 2004:

We sold our offshore division

During July 2004, we closed on the sale of our subsidiary that held our offshore assets, Denbury Offshore, Inc., for $200 million before adjustments. Expenses, closing adjustments, and interim net cash flow reduced the sale price to an estimated $187 million. The sale included total proved reserves of approximately 98 Bcfe and 54.7 MMcfe/d of production (second quarter of 2004 rate). In addition, we were able to lower our future development and plugging costs by approximately $100 million. We used the proceeds from the sale to reduce debt, leaving us with a debt to capitalization ratio of less than 20% at year-end 2004, one of the lowest leverage ratios in our history. In addition, we also removed a volatile and high finding cost segment of our business.

We added approximately 1 Tcf of proven CO_2 reserves

During 2004, we drilled four CO_2 wells at Jackson Dome, adding approximately 1 Tcf of proven CO_2 reserves, giving us approximately 2.7 Tcf of proven CO_2 reserves at year-end (before royalties and Genesis volumetric production payments). This provides us with sufficient CO_2 reserves for the first two phases of our tertiary program. We plan to drill an additional four CO_2 wells during 2005, two of which are intended to add additional CO_2 reserves for future phases of our tertiary program and two of which are acceleration wells to increase our daily CO_2 production rates.

We initiated construction of our CO_2 Pipeline to East Mississippi

With our incremental proven CO_2 reserves in hand, we began right-of-way acquisitions to build an 84-mile pipeline to our oil fields in East Mississippi. We have labeled the initial program in East Mississippi Phase II of our tertiary program and have set a target to recover up to 80 million barrels of oil reserves from the initial six fields we have reviewed. We fully expect to add additional CO_2 reserves, which would give us the ability to implement additional tertiary operations at several other fields in East Mississippi beyond Phase II, ultimately exceeding our initial estimate of 80 million barrels of incremental oil reserves.

We increased our tertiary oil production 45% year over year

Oil production from our CO_2 tertiary flooding in Southwest Mississippi (Phase 1) grew from an average of 5,579 Bbls/d in the fourth quarter of 2003 to 7,242 Bbls/d of average production in the fourth quarter of 2004, further increasing during January 2005 to an average daily rate of approximately 8,300 Bbls/d. By year-end, our tertiary oil production was approximately 25% of our total production on a BOE basis. Production growth continues at Mallalieu Field, and McComb Field has responded to the flooding earlier than expected, averaging 524 Bbls/d during the fourth quarter of 2004. During January 2005 we initiated CO_2 injections at Brookhaven Field, from which we expect an initial production response by the end of 2005.

We had another year of low finding and development cost

We added almost 19 million barrels of proved oil reserves in our tertiary program during 2004, a significant contributor to our 2004 finding and development cost of $5.30 per BOE (excluding any offshore activity, asset retirement costs and future development costs). Even after inclusion of future development and abandonment costs, our average all-in finding and development cost for the last three years is less than $8.00 per BOE. We believe this is an excellent result compared to most of the industry and provides additional justification for our strategy of adding reserves through tertiary projects.

We drilled five horizontal wells in the Barnett Shale

During 2004 we drilled our first horizontal wells in the Barnett Shale play near Fort Worth, Texas. Our results were very encouraging, with average initial production rates between 2 and 3 MMcf/d and estimated reserves of 2 to 3 Bcf per well. At year-end, we had over 62 Bcf of proved reserves in the Barnett Shale, plus an additional 125 to 150 horizontal locations. We plan to accelerate our program here in 2005 and over the next few years.

Most of our out-of-the-money hedges expired in 2004

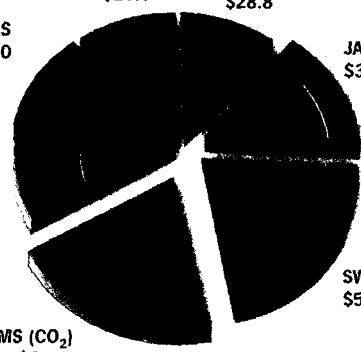
We had several oil and gas hedges that were acquired in prior years when commodity prices were lower, our debt levels were higher, and certain of our hedges were intended to protect our rate of return on acquisitions. During 2004, those hedges cost us over $7.00 per BOE. Fortunately, by year-end 2004, most of these adverse oil and gas hedges had expired, as we have hedged significantly less of our production during 2005 (as a percentage of anticipated production) and all of our 2005 oil hedges are price floors that will allow us to retain any price increases. With our low debt levels, we plan to follow the same hedging model in 2005 and beyond.

Our biggest shareholder disposed of its remaining shares

The Texas Pacific Group ("TPG"), which owned 17.5% of our stock at the beginning of 2004 and as much as 60% in prior years, successfully divested its last shares to institutional investors during March 2004. This final disposition benefited Denbury by removing a perceived overhang on our stock, as well as further improving our daily trading volumes.

We believe that these factors, combined with strong commodity prices, enabled our share price to reach new highs during 2004.

Projected 2005 Capital Budget
$260 MM[1]



[1] Excludes acquisitions and $45 million CO_2 pipeline to East Mississippi; includes allocated capitalized overhead.

Strategy

Our principal goal is to develop our tertiary oil properties using CO_2 while maintaining the conservative financial strategy we established in the aftermath of the 1998 oil price collapse. Combining the lower risk, more predictable tertiary development with the development of Barnett Shale acreage allows us to project reserve and production increases for the next several years. Our modest exploration program, primarily in Southern Louisiana, is becoming relatively smaller and we have sold our offshore division, in part because of the volatile and unpredictable nature of its reserves and production.

Our CO_2 tertiary oil strategy is driven by our ownership of significant reserves of naturally occurring CO_2 associated with a 75 million year old volcano near Jackson, Mississippi. Because there are no known competing large sources of CO_2 in the area (the nearest large sources are in Colorado and New Mexico) we enjoy a competitive advantage when acquiring mature oil fields with tertiary potential.

Injection of CO_2 for tertiary oil recovery has turned out to be the most efficient method discovered to date to produce the large quantities of oil that are left behind in reservoirs after primary and secondary (waterflood) production. The application of large scale injection, however, has been limited to those areas where quantities of CO_2 are available within economic reach of pipelines. West Texas is the largest such area, with many operators and many fields under flood, but we believe that one day the large number of old oil fields in the Gulf coast region will ultimately be within range of our CO_2 produced at Jackson Dome.

As discussed above, we have announced plans to build a CO_2 pipeline to East Mississippi as part of our expansion into Phase II. Our goal is to add other phases and we are actively pursuing additional opportunities which we hope will culminate in future phases. The key factor in the success of these future phases is not the potential oil reserves, as there are many suitable fields within range of Jackson Dome, but rather the availability of CO_2 from Jackson Dome.

We are currently undertaking an exploration program at Jackson Dome with the goal of developing enough additional CO_2 for these future phases.

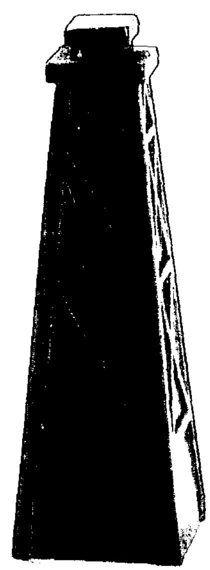
We believe that there is *significant additional* CO_2 in that area well beyond our proven 2.7 Tcf of CO_2 reserves (before royalties and Genesis' volumetric production payments). We also believe that there is an opportunity to recycle or recover CO_2 from oil fields once the tertiary oil production has ended. So far we have not assumed any recovery of CO_2 in our models (the most conservative approach) but if, for example, we are able to recover 50% of the CO_2 previously injected, then the amount of oil that could be extracted with any given volume of CO_2 would increase proportionately.

OUTLOOK

The sale of our offshore division, combined with robust oil prices, has allowed us to increase our capital spending in our CO_2 play (including Jackson Dome) to $190 million (including our pipeline to East Mississippi) in 2005 from $94 million during 2004. The majority of this spending increase is related to Phase II, which in our models is scheduled to commence injection in mid-2006, although we are hopeful that we may be able to start sooner. We also have accelerated our planned spending in the Barnett Shale play, where we plan to drill 25 horizontal wells in 2005.

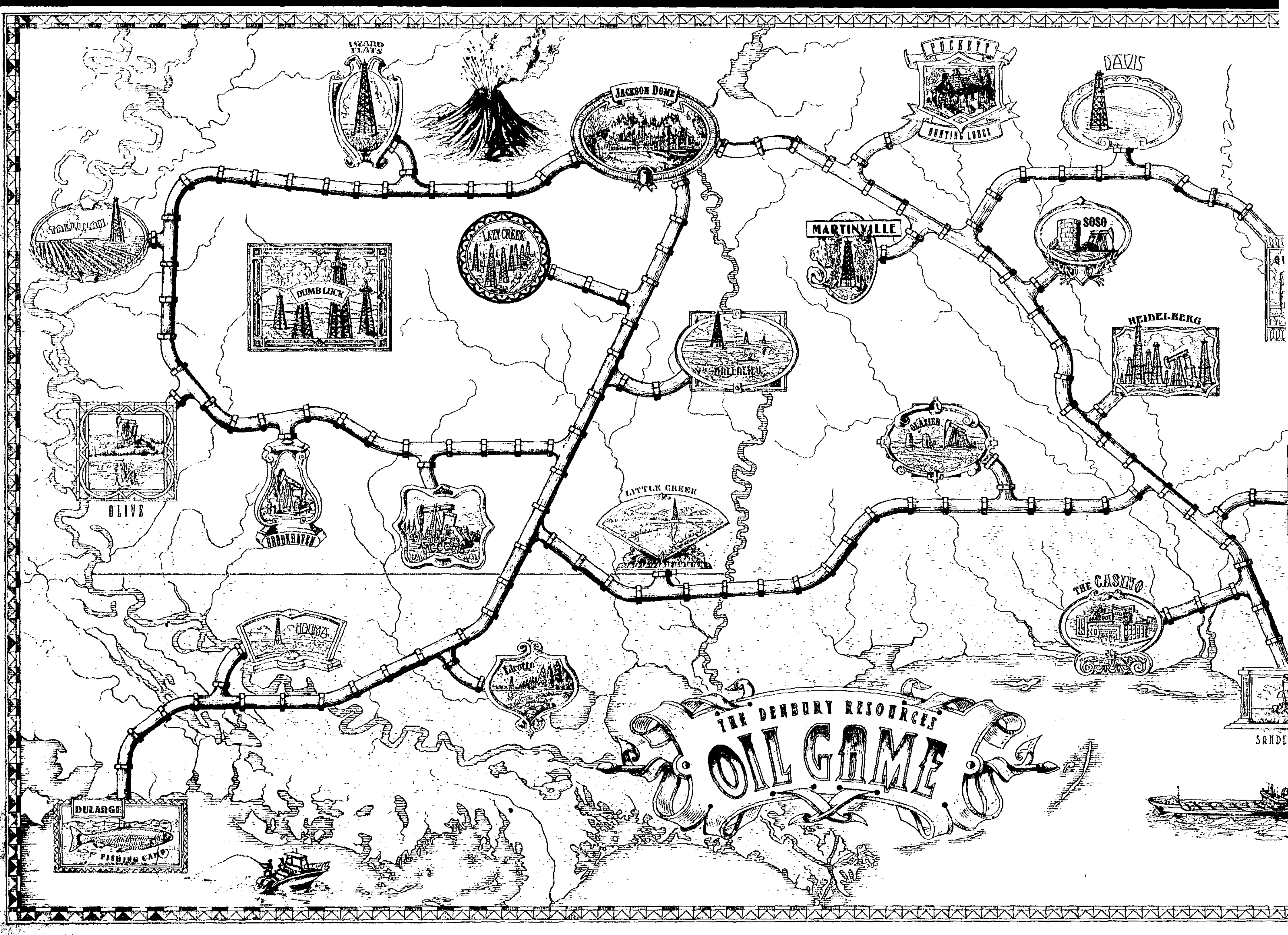
It is important to note that the combination of our CO_2 Phase I and II and Barnett Shale projects provide us with at least five years of steady development projects that can be funded from internal cash flow, assuming NYMEX oil prices of $30 or more. Because of this inventory, we feel confident that Denbury can achieve double digit organic production growth rates for the next five years without assuming any exploration success or contribution from acquisitions. It is our goal to add future tertiary recovery phases and accelerate this growth rate, plus extend our production growth curve well beyond the next five years.

Long term organic production and reserve growth are key goals for us, as we believe that the achievement of these goals will provide superior rates of returns to our shareholders and distinguish us from our peer group. This is a game that we intend to win.



GARETH ROBERTS
PRESIDENT AND CHIEF EXECUTIVE OFFICER
MARCH 10, 2005

G. Roberts

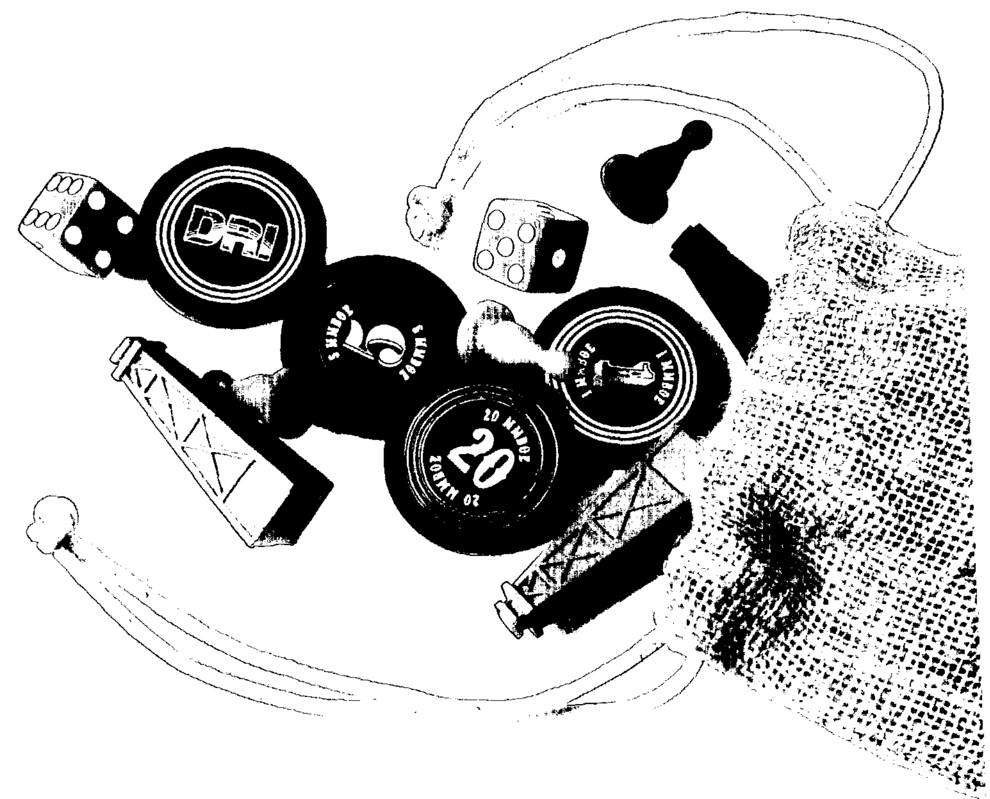

THE DENBURY RESOURCES
OIL GAME
LIZARD FLATS
JACKSON DOME
PUCKETT
HUNTING LODGE
DAVIS
LAZY CREEK
DUMB LUCK
MARTINVILLE
SOSO
HEIDELBERG
BROOKHAVEN
OLIVE
LITTLE CREEK
THE CASINO
HOUMA
DULARGE
FISHING CAMP

Selected Operating Data

Oil and Gas Reserves

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, 2004, 2003 and 2002. 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 non-producing reserves primarily relate to reserves that are to be recovered from productive zones that are currently behind pipe. Since a majority of our properties are in areas with multiple pay zones, these properties typically have both proved producing and proved non-producing reserves.



Proved undeveloped reserves associated with our CO_2 tertiary operations in West Mississippi and our Heidelberg waterfloods in East Mississippi account for approximately 96% 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 in Newark, East fields account for approximately 87% of our proved undeveloped gas reserves. The remaining undeveloped gas reserves are spread over multiple fields with the single largest field accounting for less than 5% of the total undeveloped gas reserves. This particular field's undeveloped gas reserves are currently being developed with first production expected late first quarter 2005. Our current plans for 2005 include development of 20 to 25 wells in each of our primary gas plays, Barnett Shale and Selma Chalk.

	YEAR ENDED DECEMBER 31,		
	2004	2003	2002
ESTIMATED PROVED RESERVES			
Oil (MBbls)	101,287	91,266	97,203
Natural gas (MMcf)	168,484	221,887	200,947
Oil equivalent (MBOE)	129,369	128,247	130,694
PERCENTAGE OF TOTAL MBOE:			
Proved producing	39%	43%	43%
Proved nonproducing	16%	18%	23%
Proved undeveloped	45%	39%	34%
REPRESENTATIVE OIL AND GAS PRICES: [1]			
Oil – NYMEX	$ 43.45	$ 32.52	$ 31.20
Natural gas – NYMEX Henry Hub	6.15	6.19	4.79
PRESENT VALUES:[2]			
Discounted estimated future net cash flow before income taxes ("PV-10 Value") (thousands)	$ 1,643,289	$ 1,566,371	$ 1,426,220
Standardized measure of discounted estimated future net cash flow after income taxes (thousands)	1,129,196	1,124,127	1,028,976

[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 NYMEX Henry Hub 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.

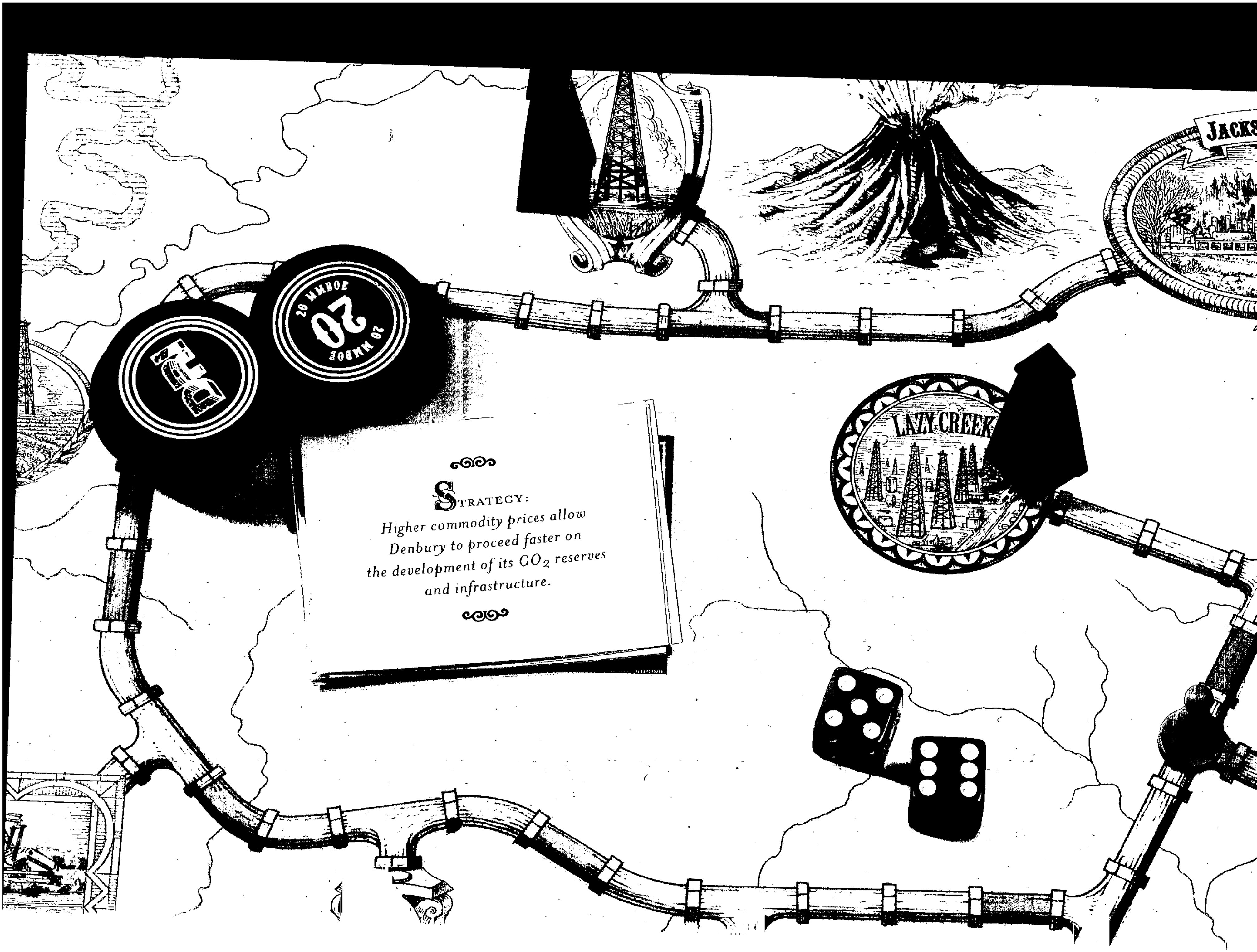
Field Summaries

Denbury operates in four primary areas: Louisiana, Eastern Mississippi, Western Mississippi, and Texas. Our 11 largest fields (listed below) constitute approximately 90% of our total proved reserves on a BOE basis and 89% on a PV-10 Value basis. Within these 11 fields we own a weighted average 89% 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 two primary field offices in Houma, Louisiana, and Laurel, Mississippi.

	PROVED RESERVES AS OF DECEMBER 31, 2004[1]					2004 AVERAGE PRODUCTION[2]		
	OIL (MBBLS)	NATURAL GAS (MMCF)	MBOE	BOE % OF TOTAL	PV-10 VALUE ($ 000'S)	OIL (BBLS/D)	NATURAL GAS (MCF/D)	AVERAGE NET REVENUE INTEREST
MISSISSIPPI CO_2 FLOODS								
Brookhaven	18,707	-	18,707	14.5%	185,962	-	-	80.7%
Mallalieu (East & West)	14,888	-	14,888	11.5%	316,010	3,351	-	80.6%
McComb/Olive	10,666	-	10,666	8.2%	158,583	285	-	75.1%
Little Creek & Lazy Creek	6,271	-	6,271	4.8%	122,320	3,148	-	83.2%
Total MS CO_2 floods	50,532	-	50,532	39.0%	782,875	6,784	-	79.7%
OTHER MISSISSIPPI								
Heidelberg (East & West)	32,577	56,575	42,006	32.5%	364,656	5,476	13,794	76.9%
Eucutta	4,485	-	4,485	3.5%	42,391	1,162	-	65.7%
King Bee	2,203	-	2,203	1.7%	22,126	460	-	79.9%
Brookhaven (non-CO_2)	1,515	-	1,515	1.2%	25,718	380	-	76.7%
Other Mississippi	8,047	6,728	9,168	7.1%	98,483	2,991	1,898	10.2%
Total Other Mississippi	48,827	63,303	59,377	46.0%	553,374	10,469	15,692	38.1%
LOUISIANA								
Lirette	97	7,029	1,269	1.0%	31,778	300	13,704	61.6%
S.Chauvin	372	11,169	2,234	1.7%	47,485	141	3,522	38.7%
Thornwell	411	6,061	1,421	1.1%	37,437	259	7,367	35.0%
Other Louisiana	1,048	18,627	4,153	3.2%	90,411	847	11,906	39.9%
Total Louisiana	1,928	42,886	9,077	7.0%	207,111	1,547	36,499	40.7%
TEXAS								
Newark (Barnett Shale)	-	62,295	10,383	8.0%	99,929	127	2,754	63.1%
Company Total	101,287	168,484	129,369	100.0%	1,643,289	18,927	54,945	51.5%

[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, 2004. The prices at that date were a NYMEX oil price of $43.45 per Bbl, adjusted by field, and a NYMEX Henry Hub natural gas price average of $6.15 per MMBtu, also adjusted by field.

[2] Does not include production on the Company's offshore properties sold in July 2004. The total average annual production on these properties was 319 Bbls/d and 27.3 MMcf/d.



STRATEGY:

Higher commodity prices allow Denbury to proceed faster on the development of its CO_2 reserves and infrastructure.

Operational Highlights

CO_2 Phase I

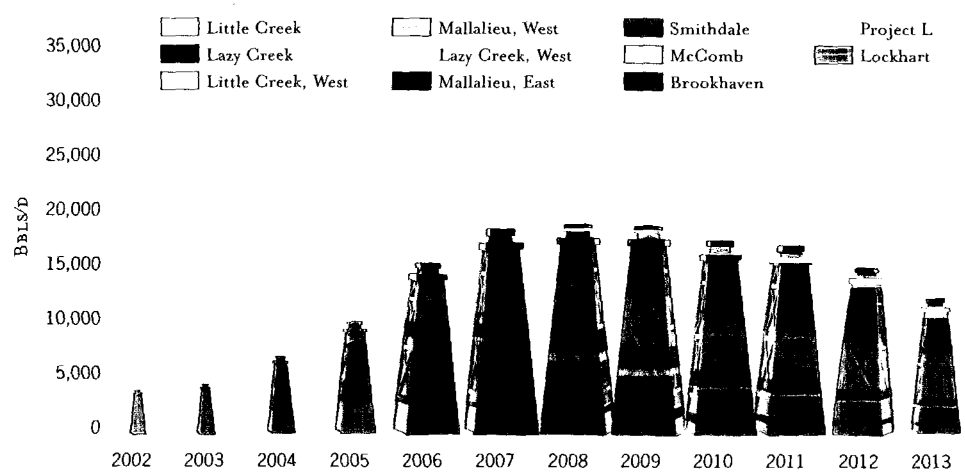
During 2004, Denbury continued its development at Little Creek, Mallalieu and McComb Fields and commenced CO_2 operations at Brookhaven Field. These four fields form the backbone of our Southwest Mississippi Phase I CO_2 tertiary injection program, which began with our acquisition of Little Creek Field in 1999. As of year end 2004 we had a total of 50.5 MMBbls of proved reserves in the Phase I fields, including 18.7 MMBbls of tertiary oil reserves recorded during 2004 at Brookhaven Field, a field where we commenced development during 2004 and started our first injections of CO_2 in January 2005. Overall oil production in Phase I has grown from an average of 5,579 Bbls/d in the fourth quarter of 2003 to 7,242 in the fourth quarter of 2004 with Mallalieu and McComb Fields registering strong increases. Injection of CO_2 at McComb began in November 2003 with its first production response occurring late in the first quarter of 2004. By the fourth quarter of 2004, McComb production had increased from virtually nothing at the time we acquired the field to a fourth quarter average of 524 Bbls/d. Approximately $51.3 million was spent on capital development in Phase I during 2004, bringing our cumulative capital expenditures for Phase I since 1999 (excluding costs at Jackson Dome) to $155.6 million. As of December 31, 2004, we had received a total of $160.0 million in net operating income (revenues less operating expenses) from Phase I, or net cash flow (revenue less operating expenses and capital expenditures) of $4.4 million, while at the same date, the SEC PV-10 Value for these fields using year-end 2004 prices of $43.45 per barrel of oil was $782.9 million.

Total all-in capital development costs inception to date for Phase I (excluding costs at Jackson Dome) are less than $6 per barrel, while operating costs are projected to average about $10 per barrel over the life of the fields. Severance taxes fluctuate with oil prices, but are expected to average at least $1 per barrel. Because there is no significant differential between the oil prices we receive in this area and NYMEX prices, the break-even oil price for this area is around $17 per barrel on a NYMEX equivalent basis.

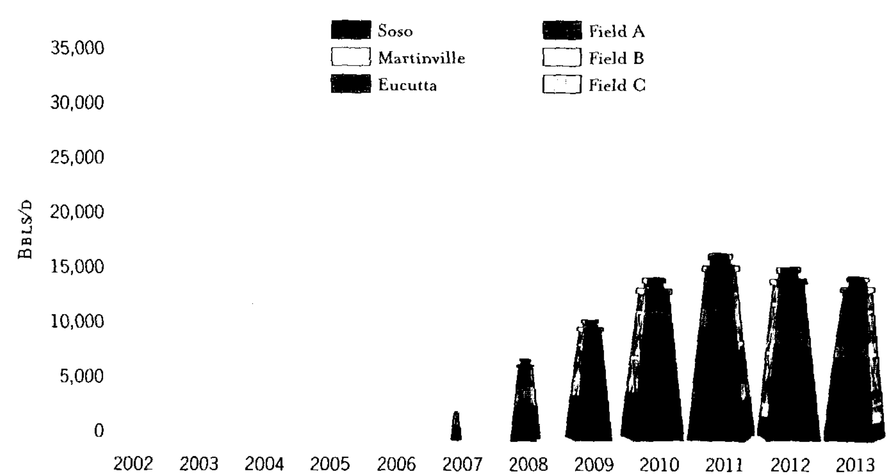
Phase I production averaged 6,784 Bbls/d in 2004, up from 4,671 Bbls/d during 2003 and is projected to increase to an average of almost 10,000 Bbls/d during 2005. Our current model projects peak production in Phase I during 2009 at over 19,000 Bbls/d.

CO_2 BUSINESS MODEL *(Tertiary Operations Only)*

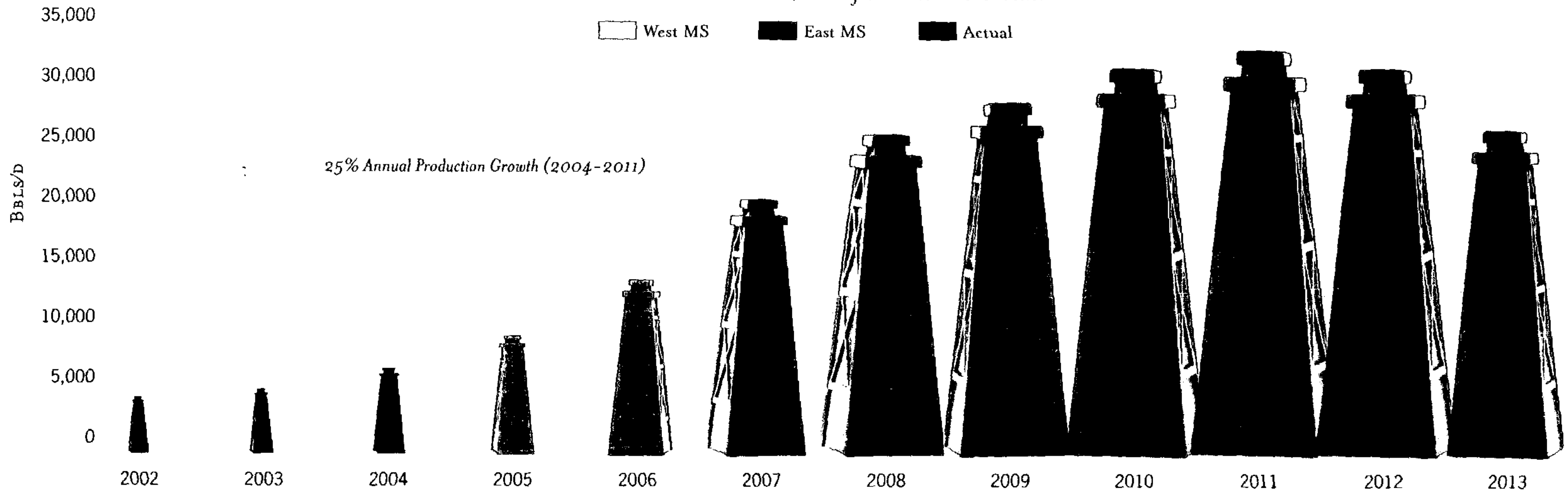
PHASE 1* *Projected Net Oil Production*



PHASE 2* *Projected Net Oil Production*



TOTAL PHASES 1 & 2* *Projected Net Oil Production*



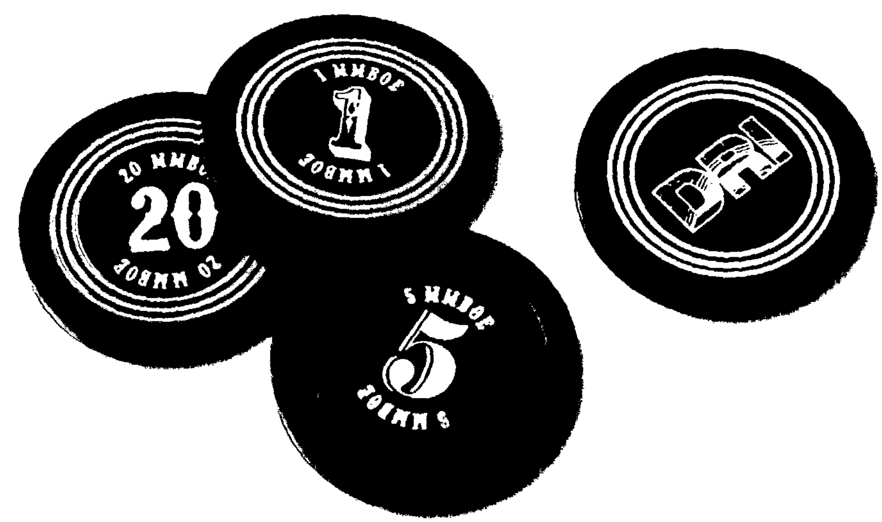
*Forecast based on internal management estimates. Actual results may vary. See the presentation on our website for a list of assumptions and cautionary note on page 24 regarding unproved reserves.

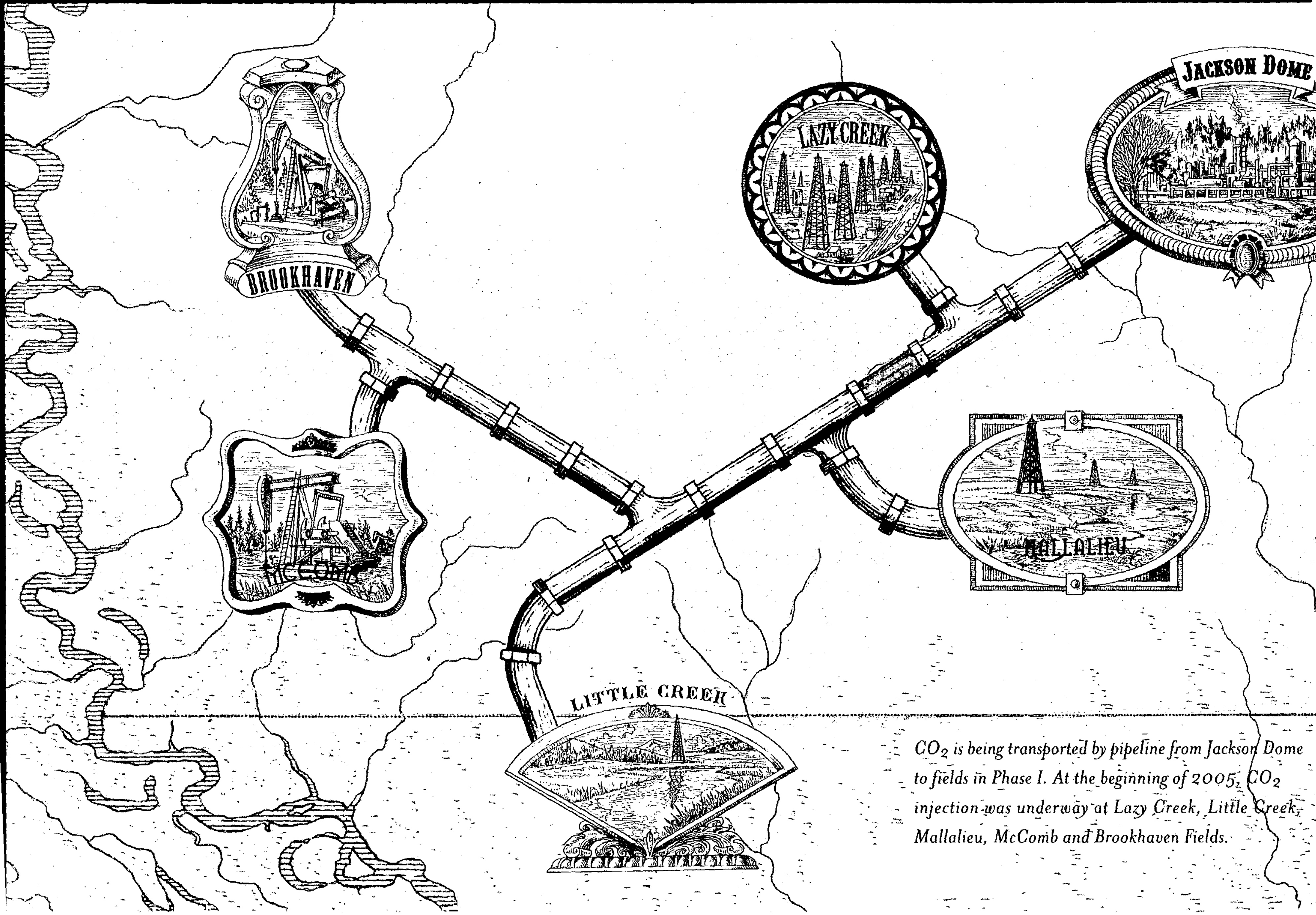
Phase II

During 2004 we announced our intention to build a pipeline to East Mississippi to commence Phase II of our tertiary program. Phase II contains six fields with about 100 MMBbls (80 MMBbls net) of potential for tertiary reserves which will require about 1.0 Tcf of CO_2 from Jackson Dome. We were able to initiate Phase II after our 2004 CO_2 drilling program proved-up the necessary CO_2 reserves at Jackson Dome. We are currently obtaining the necessary permits and rights-of-way for the pipeline and plan for it to be operational by mid-2006, hopefully sooner if things go well. A significant amount of our 2005 capital budget is being spent on the first three fields (Eucutta, Soso and Martinville Fields) in Phase II so that injection can commence as soon as the pipeline is completed. The current model for Phase II assumes CO_2 injection begins in mid-2006 with initial production response occurring in 2007. We do not have any current tertiary oil production from Phase II, but our current models project an average of about 2,500 Bbls/d in 2007, rising to a peak of about 17,000 Bbls/d in 2011. By that time, our goal would be to add additional projects to Phase II beyond the initial six fields.

The capital development costs in Phase II are expected to be about $3.00 per barrel (excluding costs at Jackson Dome) and operating costs are expected to be between $12 and $13 per net barrel, which is higher than operating costs in Phase I because of the projected pipeline transportation cost. The crude oil in this part of the state is of lesser quality than the oil produced in Phase I and receives a lower price relative to NYMEX prices. During 2004, the net price for oil sold from fields in Phase II averaged $7.70 per barrel less than NYMEX, although historically this discount has been considerably lower. Including this 2004 average differential, the break-even NYMEX oil price equivalent for Phase II is about $25 per barrel.

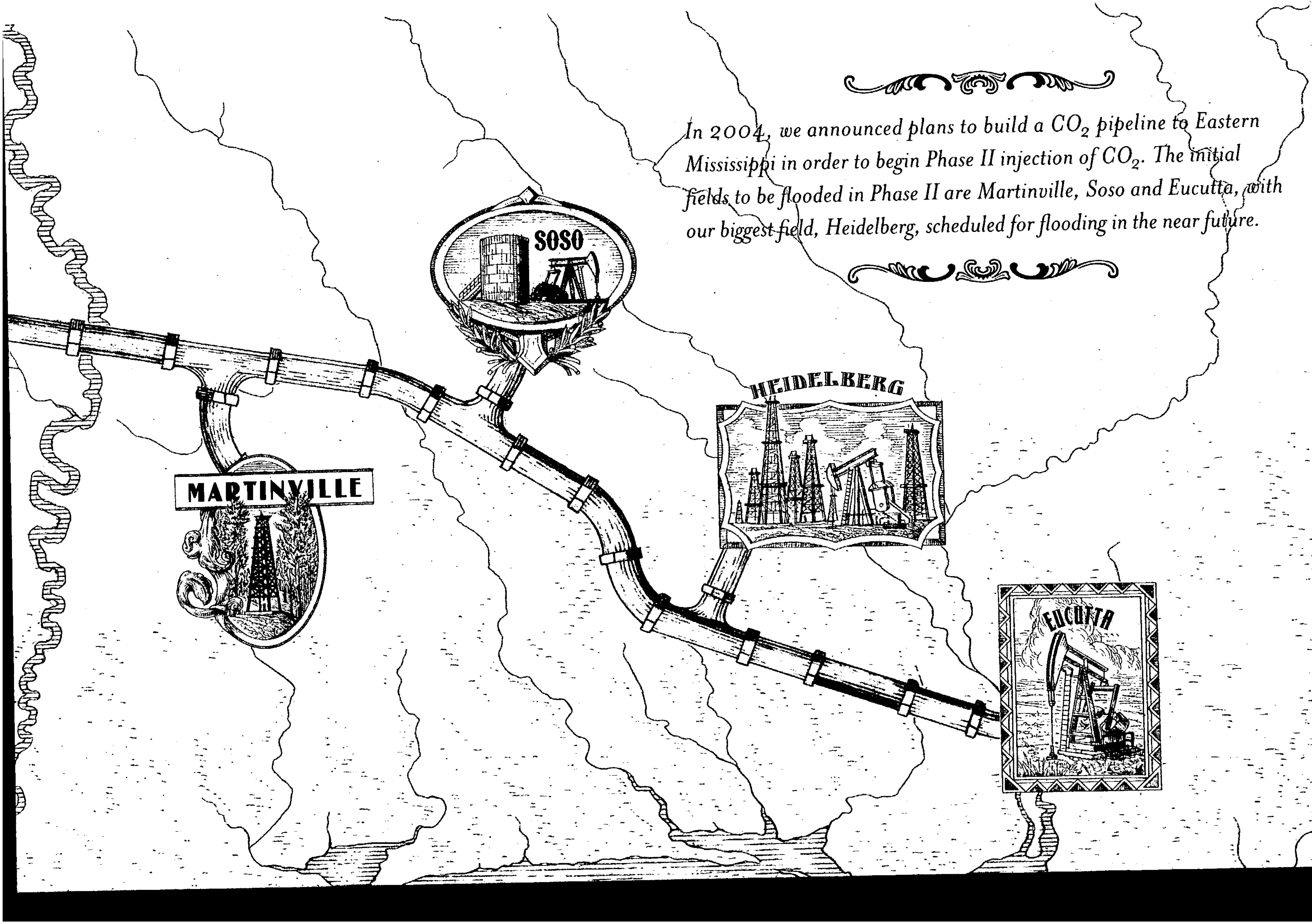
Our CO_2 tertiary oil strategy is driven by our ownership of significant reserves of naturally occurring CO_2 associated with a 75-million-year-old volcano near Jackson, Mississippi. Because there are no known competing large sources of CO_2 in the area (the nearest large sources are in Colorado and New Mexico) we enjoy a competitive advantage when acquiring mature oil fields with tertiary potential.

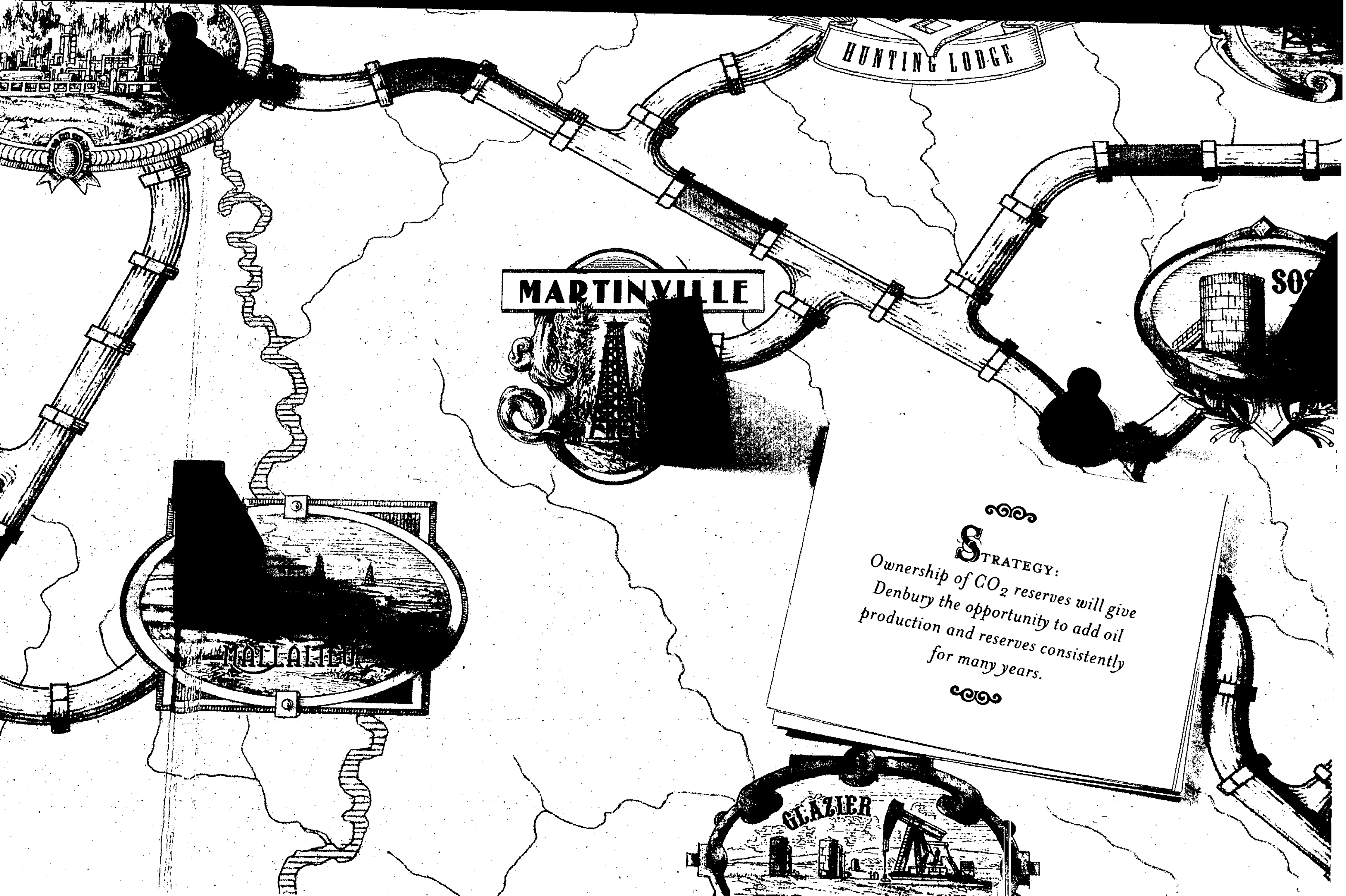




CO_2 is being transported by pipeline from Jackson Dome to fields in Phase I. At the beginning of 2005, CO_2 injection was underway at Lazy Creek, Little Creek, Mallalieu, McComb and Brookhaven Fields.

In 2004, we announced plans to build a CO_2 pipeline to Eastern Mississippi in order to begin Phase II injection of CO_2. The initial fields to be flooded in Phase II are Martinville, Soso and Eucutta, with our biggest field, Heidelberg, scheduled for flooding in the near future.





STRATEGY:

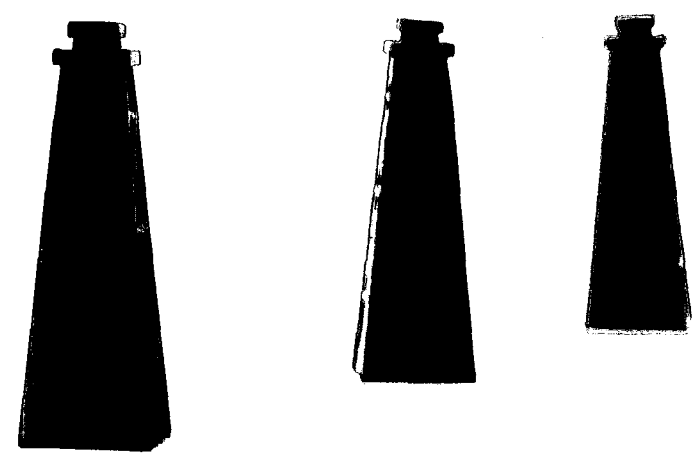
Ownership of CO_2 reserves will give Denbury the opportunity to add oil production and reserves consistently for many years.

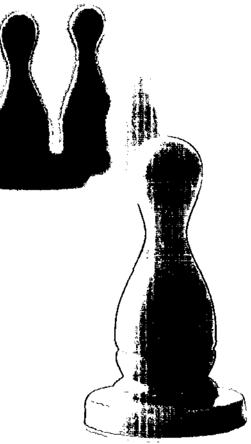
Jackson Dome (CO_2)

We drilled four wells in the Jackson Dome region in 2004, adding an additional 1 Tcf of proved CO_2 reserves, increasing the total proved CO_2 reserves available to Denbury (as determined by our independent engineers) to 2.7 Tcf on a gross basis, 2.1 Tcf net. Of this total, we estimate that between 330 Bcf and 400 Bcf is required to satisfy industrial contracts, approximately 1.2 Tcf is required for Phase I and approximately 910 Bcf is required for Phase II. Actual production rates in the fourth quarter of 2004 were 218 MMcf/d, with 69 MMcf/d going to industrial customers and 149 MMcf/d going to our Phase I fields. With the activity at Jackson Dome during 2004, we estimate that our current maximum productive capacity for CO_2 is approximately 350 MMcf/d, meaning that we had approximately 130 MMcf/d of spare capacity as of year-end 2004, although this additional capacity will be needed within the next year or two if our Phase I and Phase II development goes according to plan.

In 2004, a total of $42.5 million was spent on capital projects at Jackson Dome, which includes $37.6 million spent on drilling, $1.0 million spent on a pipeline and $4.9 million spent on a new low pressure dehydration plant that became operational by year-end, including the expenditures on leased plant equipment. Looking forward in 2005, we are planning to spend $35.1 million on four wells, a 3-D seismic survey and further infrastructure improvements. Based on the existing Phase I and Phase II models, we plan to increase our total CO_2 production at Jackson Dome to an average of 380 MMcf/d during 2005 and to a peak of 665 MMcf/d in 2009. This will satisfy the CO_2 demands of both Phase I and Phase II, and can be achieved from our existing proven CO_2 reserves. It is our intention to continue our development of these CO_2 reserves, adding both incremental production capability and additional proven reserves. Our current goal is to add an incremental 2 Tcf of CO_2 within the next two to three years, an amount that would be sufficient for a possible future Phase III and IV.

The anchor of our game plan is our CO_2 play. This play provides us with a low risk way to achieve our ultimate goal of consistent, strong, organic production growth. It allowed us to divest of our offshore division, which in turn lowered our debt and gave us the ability to accelerate our capital investments in the CO_2 play to the extent practical and economical. With our CO_2 play underpinning our entire program, we anticipate that we will be able to achieve double digit organic production growth over the next five years.





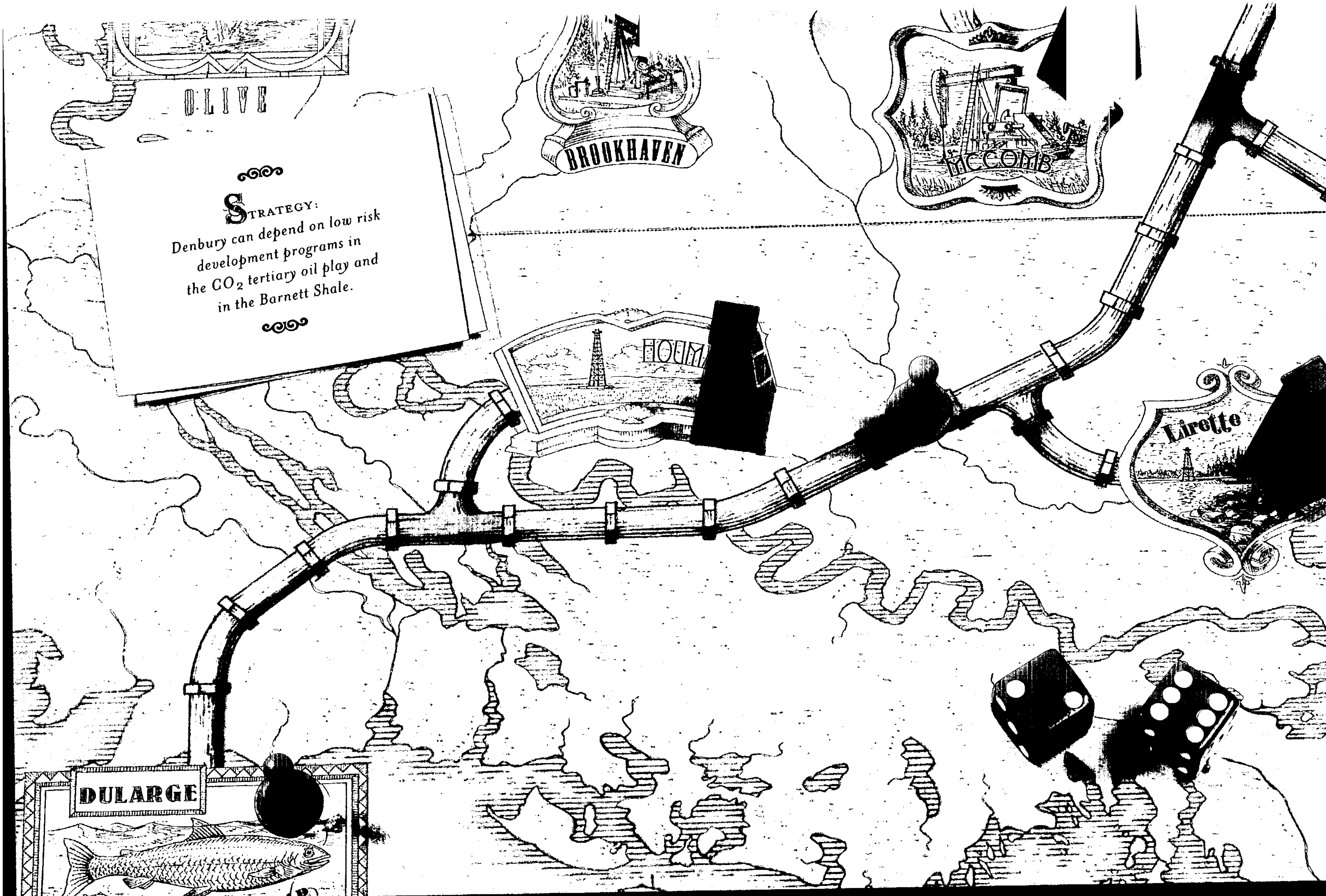
Our principal goal is to develop our tertiary oil properties using CO_2 while maintaining the conservative financial strategy we established in the aftermath of the 1998 oil price collapse. Combining the lower risk, more predictable tertiary development with the development of Barnett Shale acreage allows us to anticipate and project reserve and production increases for the next several years.

BARNETT SHALE

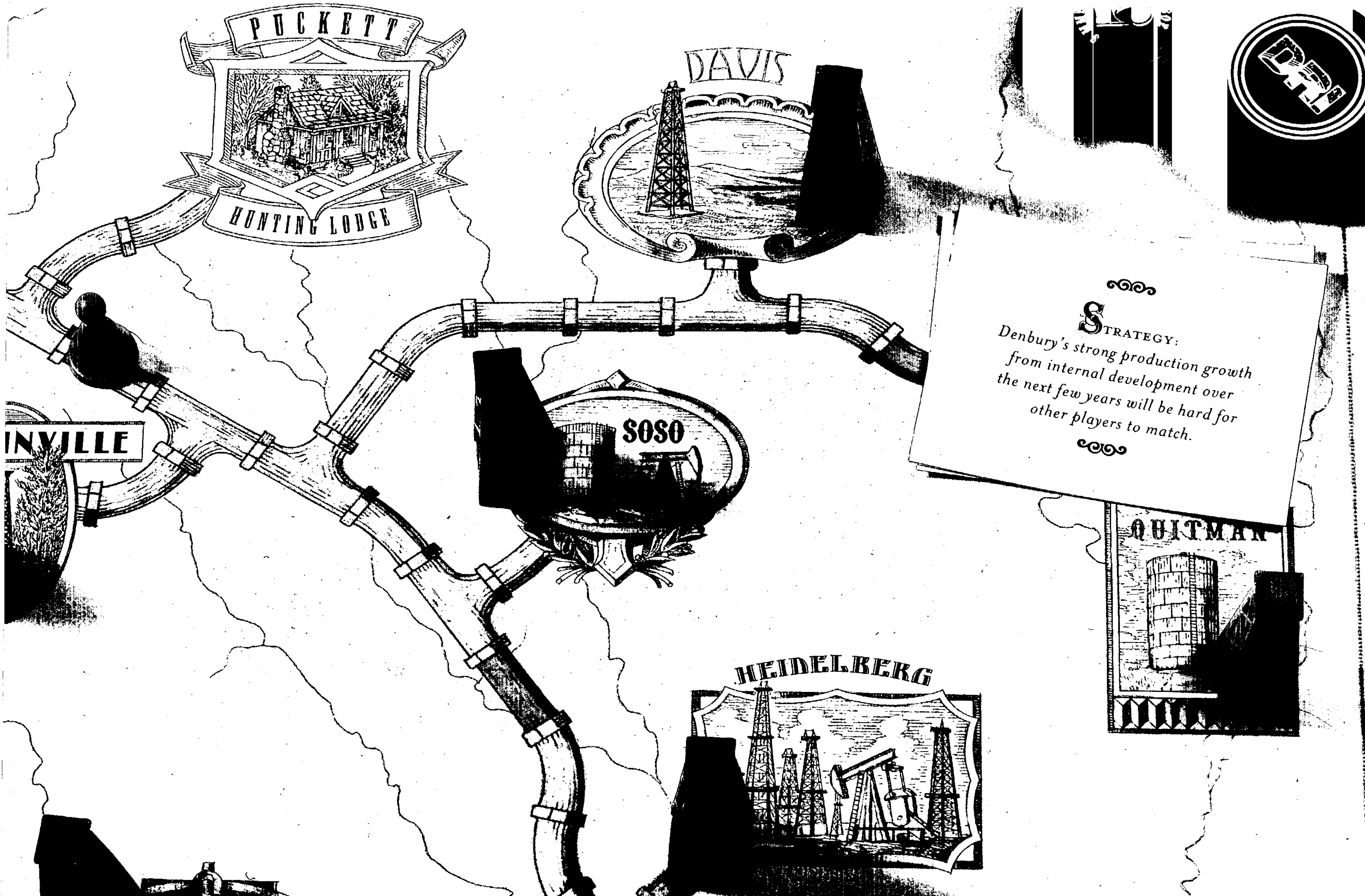
We own about 20,000 acres and interests in 29 wells in the Fort Worth Basin in North Central Texas that produces natural gas from the Barnett Shale. We acquired most of our interests here in 2001 and since then have been working to find the best way to drill, complete and produce these wells. During 2004, we drilled our first horizontal wells and are enthusiastic about our results. These horizontal wells produce at higher initial rates, decline more slowly and are simply more economical than their vertical counterparts. We are still refining our fracturing techniques on these wells, but are moving forward with our development of this acreage. During 2004, we shot 3-D seismic data over our acreage to help us better locate our wells so that we encounter less faulting and sink holes, further improving our success rate and economics. During 2005, we plan to drill 25 horizontal wells and anticipate that this level of drilling will continue for several years as we estimate that we have 125 to 150 drillable locations. We like this play as it is another relatively low-risk play, as is our tertiary operation in Mississippi. In addition to our drilling plans, we are also buying additional acreage in the area. At December 31, 2004, we have a total of 62.3 Bcf of proved natural gas reserves in the Barnett Shale with a PV-10 Value of $99.9 million using SEC year-end prices. This compares to a total investment of $27.1 million with net operating income (revenue less operating expenses) to date of $7.9 million, or an unrecovered cost of $19.2 million. We plan to spend approximately $31 million in this area during 2005.

OTHER AREAS

We also own interests in 84 wells in the land and marshes of South Louisiana and 477 wells in the eastern part of Mississippi. We are continuing to explore and develop in both of these areas using conventional techniques. We plan to spend from 10% to 20% of our budget each year on exploration activities, although with our relatively low-risk plays in Mississippi's tertiary operations and in the Barnett Shale, we are not dependent on exploratory success. We plan to spend approximately $29 million on conventional (non-tertiary) operations in East Mississippi during 2005 and about the same in South Louisiana on, or near, our existing fields in both areas. If successful, this will only further increase our anticipated production growth.


OLIVE
BROOKHAVEN
MCCOMB
HOUMA
Lirette
DULARGE
STRATEGY:
Denbury can depend on low risk development programs in the CO_2 tertiary oil play and in the Barnett Shale.

Long-term organic production and reserve growth are key goals for us as we believe that the achievement of these goals will provide superior rates of returns to our shareholders and distinguish us from our peer group. This is a game that we intend to win.



STRATEGY:
Denbury's strong production growth from internal development over the next few years will be hard for other players to match.

Contact Information

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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:	Mark Worthey, *Senior Vice President, Operations*
Accounting:	Mark Allen, *Vice President & Chief Accounting Officer*
Marketing:	Ron Gramling, *Vice President, Marketing*
Exploration:	Jim Sinclair, *Vice President, Exploration*
Land:	Ray Dubuisson, *Vice President, Land*
Louisiana Division:	George Pecorino, *Houma, LA*
Mississippi Division:	Kerry Allen, *Laurel, MS*

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 reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. We use certain terms in the preceding section of this annual report, such as probable and potential reserves or production forecasts derived from such probable and potential reserves, that the SEC's guidelines strictly prohibit us from 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, and other enumerated reserve potential. These forward-looking statements are generally accompanied by words such as "estimated", "projected", "potential", "anticipated", "forecasted" or other words that convey the uncertainty of future events or outcomes. These statements are based on management's current plans and assumptions and are subject to a number of risks and uncertainties as further outlined in our most recent 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.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

(Mark One)

2004 FORM 10-K

_X_ Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2004

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 3000, 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 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. [X]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). [X]

As of June 30, 2004, the aggregate market value of the registrant's Common Stock held by non-affiliates was approximately $1.1 billion.

The number of shares outstanding of the registrant's Common Stock as of February 28, 2005, was 56,612,005.

DOCUMENTS INCORPORATED BY REFERENCE

Document	Incorporated as to
1. Notice and Proxy Statement for the Annual Meeting of Shareholders to be held May 11, 2005.	1. Part III, Items 10, 11, 12, 13, 14

2004 ANNUAL REPORT ON FORM 10-K
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GLOSSARY AND SELECTED ABBREVIATIONS

Bbl	One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.
Bbls/d	Barrels of oil produced per day.
Bcf	One billion cubic feet of natural gas 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 & 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.*

PART I

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") 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 and the Barnett Shale in Texas. Our corporate headquarters is located at 5100 Tennyson Parkway, Suite 3000, Plano, Texas 75024, and our phone number is 972-673-2000. At December 31, 2004, we had 380 employees, 243 of which were employed in field operations or at the field offices. Our employee count does not include the approximately 200 employees of Genesis Energy, Inc. as of December 31, 2004 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. The purposes of creating the holding company structure were to better reflect the operating practices and methods of Denbury, to improve its economics, and to provide greater administrative and operational flexibility. 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). The reorganization was structured as a tax free reorganization to Denbury's stockholders and all outstanding capital stock of the original public company was automatically converted into the identical number of and type of shares of the new public holding company. 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. The new parent holding company is co-obligor (or guarantor, as appropriate) regarding the payment of principal and interest on Denbury's outstanding debt securities.

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

Just over five years ago, we started a new focus area through an acquisition of a carbon dioxide ("CO_2") tertiary flood in an area very familiar to us, Mississippi. We have subsequently acquired other related assets and are making that focus area the major part of our business. We particularly like this tertiary play as (i) it is lower risk and more predictable than most traditional exploration and development activities, (ii) it provides a reasonable rate of return at relatively low oil prices (low to mid twenties), and (iii) we have virtually no competition for this type of activity in our current geographic area. Generally, from East Texas to Florida, there are no known natural sources of carbon dioxide except our own, and these large volumes of CO_2 that we own drive the play. Our CO_2 comes from an old underground volcano located near Jackson, Mississippi, discovered in the 1960s while companies were drilling for oil and natural gas. These CO_2 reserves are found in structural traps in the Haynesville, Buckner, Smackover and Norphlet formations at depths of about 16,000 feet.

CO_2 injection is one of the most efficient tertiary recovery mechanisms for producing crude oil; however, because it requires large quantities of CO_2, its use has been restricted to West Texas, Mississippi and other isolated areas where large quantities of CO_2 are available. The CO_2 (in liquid form) acts as a type of solvent for the oil, causing the oil to expand and become mobile, allowing the oil to be recovered along with the CO_2 as it is produced. The CO_2 is then extracted from the oil, compressed back into a liquid state, and re-injected into the reservoir, with this recycling process occurring several times during the life of the tertiary operations. In a typical oil field up to 50% of the oil in place can be extracted during primary and secondary (waterflooding) recovery operations. Through the use of CO_2 in tertiary operations, it is possible to recover additional oil (for example, 17% based on historical results at Little Creek), almost as much oil as initially recovered during the primary production phase.

We started this play in August 1999, when we acquired our first CO_2 tertiary recovery project, Little Creek Field in Mississippi, a project originally developed by Shell Oil Company. Since our acquisition of this field, we have increased oil production here from 1,350 Bbls/d to an average of 2,989 Bbls/d during the fourth quarter of 2004. Following our success at Little Creek, we embarked upon a strategic program to build a dominant position in this niche play. We recognized that several other fields in the area would also be excellent CO_2 flood candidates because they produced from the same Lower Tuscaloosa formation, shared very similar reservoir characteristics and were in close proximity to each other. Following are highlights of our activities over the last three years:

- 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 because it assured us that CO_2 would be available to us on a reliable basis and at a reasonable and predictable cost. Since February 2001, we have acquired two and drilled seven additional CO_2 producing wells, more than tripling our estimated proved CO_2 reserves to approximately 2.7 Tcf as of December 31, 2004. The estimate of 2.7 Tcf of proved CO_2 reserves is based on 100% ownership of the CO_2 reserves, of which Denbury's net ownership is approximately 2.1 Tcf and is included in the evaluation of proven CO_2 reserves prepared by DeGolyer & MacNaughton and included as Exhibit 99. 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 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.

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 the additional CO_2 deliverability, we plan to drill several additional CO_2 wells in the future, including up to four more wells during 2005.

- During 2001 and 2002, we acquired several oil fields in our CO_2 operating area, including the West Mallalieu and McComb Fields. Typical of mature properties in this area, the acquisition costs of both of these fields were relatively low in comparison to their significant reserve potential as tertiary recovery projects. As an example, we acquired West Mallalieu Field in May 2001 for $4.0 million, and by year-end 2001 had recognized 10.4 MMBOE of proved reserves, with additional future reserve potential in this field. We acquired McComb Field in 2002 for $2.3 million, and by year-end 2002 had recognized 8.3 MMBOE of proved reserves with additional future reserve potential here also.
- In August 2002, we acquired COHO Energy Inc.'s Gulf Coast properties for $48.2 million, which included Brookhaven Field, another significant tertiary flood candidate along our CO_2 pipeline. Initial development of the Brookhaven CO_2 flood began in late 2004. DeGolyer & MacNaughton has estimated that 18.7 MMBbls of oil reserves can be recovered from Brookhaven Field from our CO_2 tertiary operations in their December 31, 2004 proved reserve report.
- During the fourth quarter of 2004, we sold an average of 69 MMcf/d of CO_2 to commercial users and we used an average of 149 MMcf/d for our tertiary activities. We estimate that our current daily CO_2 deliverability is approximately 350 MMcf/d, and by year-end 2005 we hope to further increase our CO_2 deliverability to between 450 MMcf/d and 500 MMcf/d. We plan to continue our CO_2 drilling in 2005 and beyond, as we estimate that we will need up to 700 MMcf/d in the next few years in order to meet the projected timetable for our tertiary projects in Southwest and East Mississippi. During 2004, two of the CO_2 wells we drilled tested new structures that increased our CO_2 reserves by approximately 1 Tcf of CO_2. These wells will be brought online once we install the facilities that are necessary to produce these wells at their maximum rates. With the increase in our CO_2 deliverability and reserves, we made the strategic decision to commence with installation of a pipeline to several of our East Mississippi properties, and expect to commence CO_2 operations in three East Mississippi fields by mid-2006. As of December 31, 2004, the calculated present value of the remaining industrial sales contracts (using pricing provided in the contracts) discounted at 10% per year was approximately $26.5 million based on the current life of each contract.
- In October 2003 and September 2004, we sold 167.5 Bcf and 33.0 Bcf of CO_2 to Genesis for $24.9 million and $4.8 million under two separate volumetric production payments. In conjunction with the sale, we included the assignment of four of our existing long-term commercial CO_2 supply agreements with our industrial customers. Pursuant to the terms of the volumetric production payments, Genesis has specific maximums on the amount of CO_2 they are allowed to take each year, which generally relate to the anticipated volumes of the four industrial customers. We provide Genesis with certain processing and transportation services in connection with these agreements for a fee of approximately $0.16 per Mcf of CO_2 delivered to their industrial customers.
- During the fourth quarter of 2004, we commenced operations to expand our tertiary program to East Mississippi and have commenced the acquisition of leases and right-of-way for the construction of an 84-mile CO_2 pipeline from our source wells near Jackson, Mississippi to Eucutta Field in East Mississippi. We believe that this expansion into East Mississippi, labeled Phase II, has significant oil potential beyond the first six fields that we have engineered and plan to flood. Combining the production forecast for both of these areas (Phase I and II) extends the period during which we anticipate significant oil

production growth from a few years, for Phase I alone, to five to ten years combined. 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 will be the backbone of our Company's growth for the foreseeable future.

With anticipated all-in finding and development costs (including future development and abandonment costs) of around $6.00 per BOE and anticipated operating costs of around $10.00 per BOE over the life of each field, our tertiary recovery operations in West Mississippi along our pipeline should provide a reasonable rate of return at oil prices in the low twenties, as they produce light sweet oil that receives near NYMEX pricing. The economics will be a little different in East Mississippi (Phase II) in the following ways: (i) operating costs in East Mississippi are likely to be one to three dollars per BOE higher than it is for those fields along our existing CO_2 pipeline, primarily because of the incremental cost of transporting the CO_2 to this new area (assuming another party ultimately owns the pipeline and we pay a throughput or transportation fee), (ii) the incremental operating cost may be partially offset by an anticipated lower finding cost, as these East Mississippi fields may not require as many wells to be drilled or re-entered, as more wells are currently active, (iii) there are reservoir related differences, which although not exactly quantified, are expected to improve the overall economics in the eastern area, and (iv) the quality of the oil is different in the two areas. In the eastern part of the state, the oil is generally heavier and usually sour, and thus has a higher negative differential to NYMEX prices, ranging historically from one to six dollars per barrel lower than West Mississippi light sweet oil. During the fourth quarter of 2004, the differentials for these heavier crudes widened to as much as $13 to $16 per barrel, but we expect the differentials to return to their historical levels over time. In summary, while the fields in West Mississippi along our pipeline provide a satisfactory rate of return at NYMEX oil prices in the low twenties, we project that it takes NYMEX oil prices in the mid to high twenties to achieve similar rates of return in East Mississippi.

Tentatively, we plan to spend approximately $35 million in 2005 in the Jackson Dome area targeted to add additional CO_2 reserves and deliverability for future operations. Approximately $60 million in capital expenditures is budgeted in 2005 for our oil fields with tertiary operations in Southwest Mississippi and approximately $50 million for oil fields in East Mississippi, plus an additional $45 million for the CO_2 pipeline to East Mississippi, increasing our combined CO_2 and tertiary recovery related expenditures to over 60% of our current 2005 capital budget.

OUR TERTIARY OIL FIELDS

Little Creek Field was discovered in 1958, and by 1962 the field had been unitized and waterflooding had commenced. The pilot phase of CO_2 flooding began in 1974 and the first two phases (each in a distinct area of the field) began in 1985. When we acquired the field in 1999, the first two phases were complete and the third phase was in process. We have completed development of the third, fourth and fifth phases and most of the currently planned development work at this field, although we will continue to modify existing patterns and drill wells as necessary to recover the maximum amount of oil or to extend the field into areas that have not benefited from CO_2 injection. Currently there are 28 producing wells and 34 injection wells at Little Creek. Based on the results of the two earliest phases of CO_2 flooding at Little Creek, tertiary recovery has increased the ultimate recovery factor in the flooded portion of the field by approximately 17%, as compared to recoveries of approximately 20% for primary recovery and 18% for secondary recovery. The field has produced a cumulative 16 MMBbls (gross) of light sweet crude, as a result of tertiary operations, and we currently estimate that an additional 6.1 MMBbls (gross) can be recovered.

Production from Little Creek Field was approximately 1,350 Bbls/d when we acquired the field in 1999. During the fourth quarter of 2004, production had increased to an average of 2,989 BOE/d (including Lazy Creek). We expect the production from Little Creek to increase further during 2005 by another 150 to 250 BOE/d. From inception through December 31, 2004, we had net positive cash flow (revenues less operating expenses and capital expenditures) from Little Creek (including Lazy Creek) of $48.5 million (at the field level), plus the fields have a PV-10 Value, using December 31, 2004 SEC NYMEX pricing, of $122.3 million.

We purchased West Mallalieu Field in May 2001. Shell Oil Company unitized West Mallalieu Field and commenced a pilot project in 1986. The pilot project, consisting of four 5-spot patterns, has cumulatively produced approximately 2.1 MMBbls of oil as a result of CO_2 flooding. We have expanded the pilot project by adding four additional patterns during 2001, four patterns in 2002, three patterns in 2003, and two patterns in 2004. We also completed our first pattern in East Mallalieu during 2004. During 2002 we began to see initial response to CO_2 injection as the West Mallalieu Field averaged 778 Bbls/d during the fourth quarter of 2002. Response continued throughout 2003 and 2004, averaging 3,712 Bbls/d during the fourth quarter of 2004. In contrast to Little Creek Field, 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 exceed the 17% of original oil in place that we expect from Little Creek Field.

We purchased McComb Field in 2002, a field with no pilot programs or tertiary operations at that time and virtually no current oil production. McComb is very close in proximity and analogous to Little Creek and Mallalieu Fields. We commenced tertiary recovery operations in 2003 by substantially completing two patterns, and by November 2003 had started injecting CO_2. Significant development occurred during 2004 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 patterns. The production response occurred earlier than expected, with the field averaging 540 Bbls/d in the fourth quarter of 2004. During 2005, we expect to add three patterns within McComb Field and further expand the production facilities. In addition, we also started our initial work on an additional CO_2 flood at nearby Smithdale Field during 2004 utilizing the same CO_2 facilities, with CO_2 injections expected to begin in early 2005. We believe that the total potential at McComb and Smithdale Fields is significantly higher than the current proved reserves (at McComb only), and therefore expect to add additional reserves and have upward reserve revisions here over the next several years as we fully develop these fields.

Initial development of the Brookhaven Field, a field acquired during 2002 in the COHO acquisition, began in late 2004 with the first injections of CO_2 in January 2005. During 2005, we plan to complete development of the two patterns initiated in 2004 and develop an additional seven patterns, but do not expect any significant production response from this field until early 2006.

At December 31, 2004, we have proved reserves of 50.5 MMBbls relating to our tertiary recovery operations. Through December 31, 2004, we have spent a total of $155.6 million on fields in this area, and have received $160.0 million in net operating income (revenue less operating expenses), or net positive cash flow of $4.4 million. These amounts do not include the capital costs or related depreciation and amortization of our CO_2 producing properties at Jackson Dome, which had a net unrecovered cost balance of $75.4 million as of December 31, 2004. At year-end 2004, the proved oil reserves in our CO_2 fields had a PV-10 Value, using December 31, 2004 SEC NYMEX pricing, of $782.9 million.

HEIDELBERG AND EAST MISSISSIPPI

We own interests in 477 wells in the eastern part of the Mississippi salt basin and operate 436 of these wells (91%) from our regional office in Laurel, Mississippi. These fields produced an average of 10,601 Bbls/d and 17.8 MMcf/d during the fourth quarter of 2004. We have been active in this area since Denbury was founded in 1990 and are by far the largest producer in the basin, as well as in the state of Mississippi. Since we have generally owned these eastern Mississippi properties longer than properties in our other regions, they tend to be more fully developed. During 2004, we spent a total of approximately $38.4 million (excluding acquisitions), drilling 53 wells and performing various workovers and recompletions. Production in eastern Mississippi averaged 13,085 BOE/d during 2004, down slightly from the 2003 average of 13,638 BOE/d. For 2005, we expect our budget in this region for conventional operations to be a little lower than it was in 2004, approximately $28.6 million, or 9% of our current 2005 exploration and development budget of $305 million (including the East Mississippi CO_2 pipeline), and as discussed above, we have budgeted an additional $50.2 million to initiate three tertiary recovery projects at Martinville, Soso and Eucutta Fields.

The fields in this region are characterized by structural traps that generate prolific production from stacked or multiple pay sands. As such, they provide opportunities to increase reserves through infield drilling, recompleting wells, improving production efficiency, and in some cases, by water flooding producing reservoirs. Most of our wells in this area produce large amounts of saltwater and require large pumps, which increase the operating costs per barrel relative to our properties in Louisiana that are predominantly natural gas producers. We plan to continue our basic strategy in this region, supplemented by additional waterflooding (secondary recovery) and tertiary operations.

The largest field in the region, and our largest field corporately, is Heidelberg Field, which for the fourth quarter of 2004 produced an average of 8,266 BOE/d. Heidelberg Field was acquired from Chevron in December 1997. This field was discovered in 1944 and has produced an estimated 204 MMBbls of oil and 57 Bcf of gas since its discovery. 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 primary oil production at Heidelberg is from five waterflood units that produce from the Eutaw formation (at approximately 4,400 feet). These units are generally developed although they will require additional work and capital for the next few years. In addition, Heidelberg is our second largest gas field. We began extensive development of the Selma Chalk natural gas reservoir at a depth of 3,700 feet in 2000 and 2001. Previous operators had only partially developed this formation in order to provide fuel gas for the rest of the field. We drilled 13 to 15 wells each year in 2001, 2002 and 2003, with an additional 24 natural gas wells drilled in 2004, increasing the natural gas production at Heidelberg to an average for 2004 of approximately 13.8 MMcf/d. We believe that there are opportunities to expand the field limits, to continue reducing the well spacing and to stimulate the Upper Selma Chalk to achieve additional gas reserves in the Selma Chalk. We plan to drill 16 additional gas wells here during 2005, including our first horizontal test in the Selma Chalk.

EUCUTTA FIELD

Eucutta Field was purchased from Amerada Hess in 1995. The field is very analogous to Heidelberg Field in that the majority of its historical production was produced from the Eutaw formation. 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 pilot test in the 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 test was successful in recovering an additional 17% of the original oil in place within the pattern. Based on this success, we have designed a CO_2 project for the Eucutta Field and plan to build our CO_2 facilities and develop three patterns during 2005. Initial injection of CO_2 is projected to commence mid-2006, although it could start earlier if our CO_2 pipeline to East Mississippi is completed sooner.

SOSO FIELD

Soso Field was purchased from COHO Resources in 2002. Although this field produces from numerous sands, the majority of our work in 2005 will involve the building of CO_2 facilities and establishing two patterns in the Bailey sand and two partial patterns in the Cotton Valley sands. This field has not had any previous CO_2 injection or pilot projects. In reviewing Soso Field we studied the Bailey sand which was one of the more prolific reservoirs within the field and exhibited characteristics of a depletion drive reservoir. The Bailey reservoir oil is 43.4 API gravity, similar to our West Mississippi floods, and is at approximately the same depth and has very similar reservoir characteristics, thus we expect the Bailey tertiary flood to perform in a similar manner to our West Mississippi CO_2 floods.

MARTINVILLE FIELD

Martinville Field was purchased from COHO Resources in 2002. As is the case with all of the East Mississippi fields, Martinville produces from multiple reservoirs. Unlike the majority of our other planned CO_2 projects, Martinville does not contain one very large reservoir to CO_2 flood, but rather several smaller reservoirs. We have identified three CO_2 formations at Martinville on which we plan to initiate CO_2 flooding following completion of our East Mississippi CO_2 pipeline. The first reservoir to be CO_2 flooded is the Mooringsport, which, because it has been waterflooded very successfully, is expected to CO_2 flood successfully as well. We plan to install the required CO_2 facilities and essentially complete the development of the Mooringsport during 2005. The second reservoir, the Rodessa, has similar reservoir characteristics to the Mooringsport. We expect to initiate injection into the Rodessa with the completion of one injector. The final reservoir is the Wash Fred 8500' reservoir. This reservoir contains a low gravity oil, 15 API, which will clearly 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 gravity oil and a strong water drive which does not drive the oil efficiently. We plan to initiate injection into the Wash Fred 8500' reservoir at the crest of the structure, allow the CO_2 to swell the oil, decrease the oil viscosity, and displace the water and oil downward in the reservoir to the producing wells. Successful implementation of a CO_2 project in the Wash Fred 8500' reservoir would provide the impetus to look at a whole new set 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.

TEXAS AND THE BARNETT SHALE

We own about 20,000 acres of leases and working interest in 29 wells in the Fort Worth Basin in North Central Texas that is prospective for natural gas in the Barnett Shale. We currently operate 18 of the producing wells with essentially 100% ownership in most of the remaining development potential. We acquired the majority of this acreage in 2001 and have been working to find the optimum method to drill, complete and produce the Barnett Shale. We drilled six wells in 2001, two in 2002, five in 2003 and 18 in 2004, seven by us and 11 under a farmout arrangement where we retained a 25% working interest. During 2004 we drilled our first three horizontal wells that produced at much higher initial rates and declined slower than our previous vertical wells. As a result of this initial success, we expanded our 2004 capital budget and drilled four additional horizontal wells. The average initial producing rate for these 2004 horizontal wells is approximately 2 MMcf/d. We are still refining our fracturing technique, including an analysis of the best number of fracture treatments to adequately stimulate the entire length of our lateral sections, which can exceed 4,000 feet. Initial reserve estimates for these horizontal wells appear to be 3 to 4 times greater than the vertical wells we initially drilled. Although our production during the fourth quarter of 2004 averaged only 4.4 MMcf/d, we expect production in this area to grow substantially during 2005. During 2005, we plan to drill approximately 25 horizontal wells. Including seismic costs and pipeline infrastructure costs, our planned 2005 capital expenditures in the Barnett Shale is estimated to be $31 million of our $305 million capital budget (including the East Mississippi CO_2 Pipeline).

During 2004, we also committed the necessary capital to shoot 3-D seismic data over our entire acreage position, 50 to 60 square miles. We received our first seismic data in February 2005 and expect to have the majority of the remaining data by May 2005. The 3-D seismic data should allow us to 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.

During 2004, we continued to address the issue of pipeline capacity in our area of the Barnett Shale play by installing additional pipelines to relieve some packed lines. The largest gas purchaser in the area is installing a new 20" gas line to handle the increasing volumes of gas in our area. In addition, several other gas buyers and pipeline companies are entering the area and making plans to install additional pipelines to handle the anticipated future volumes of gas.

SOUTH LOUISIANA

We own interests in 84 wells in the land and marshes of south Louisiana and one non-operated offshore well that we did not include in our 2004 sale of offshore properties. We operate 71 of these wells (85%) from our regional office in Houma, Louisiana. This region produces primarily natural gas, averaging 33.7 MMcf/d net to our interest in the fourth quarter of 2004, approximately 60% of our total natural gas production. During 2004, we spent approximately $23.7 million (excluding acquisitions) in this region, approximately 11% of our total exploration and development expenditures, drilling approximately 10 wells, primarily in the Thornwell and Terrebonne Parish areas. For 2005, our spending is expected to be about the same, with a budget of $28.8 million, or 9% of our $305 million exploration and development budget (including our East Mississippi CO_2 pipeline).

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. The advent of 3-D seismic data in these geologically complex areas has become a valuable tool in exploration and development. We currently own or have a license covering over 1,000 square miles of 3-D data, and plan to expand our data ownership during 2005. During 2004, we expanded our seismic holdings in this area by acquiring an additional 188 square miles of 3-D data. We drilled seven wells in Terrebonne Parish during 2004, four of which were successful. In 2005, we plan to drill approximately six exploratory wells in Terrebonne Parish and three development wells.

Historically we have had good success with a shallow natural gas play in Terrebonne Parish. These shallow gas reservoirs are approximately 3,000 feet deep, but have the ability to produce from 1.0 to 4.0 MMcf/d. During 2004, we drilled one successful and one unsuccessful well. We plan to drill an additional 6 shallow gas prospects in Terrebonne Parish during 2005, with another 5 to 15 additional shallow gas prospects in Terrebonne Parish under review.

Thornwell Field is characterized by short-life natural gas properties that have high initial production rates with a good rate of return, but which are depleted in two to three years. The high rates of decline have dramatically impacted our overall production rates the last two years, and are expected to continue to do so throughout 2005. Production at Thornwell Field averaged 4,275 BOE/d in 2001, 3,910 BOE/d in 2002, 2,564 BOE/d in 2003 and 1,487 BOE/d in 2004, and is expected to average approximately 750 BOE/d during 2005. Even though this field has negatively affected our overall production growth, the purchase and development of this field has been profitable. We had significant activity at this field during 2001 and 2002, with positive results, but reduced our activity during 2003 and 2004 as the field became more fully developed. Our plans for 2005 include the drilling of one exploratory well to test the Marg Tex/Bol Mex sands and two development wells in the Bol Perc. From inception through December 31, 2004, we have net positive cash flow (revenue less operating expenses and capital expenditures) to date of $37.0 million from this field, with a remaining proved PV-10 Value, using December 31, 2004 constant SEC NYMEX pricing, of $37.4 million.

FIELD SUMMARIES

Denbury operates in four primary areas: Louisiana, Eastern Mississippi, Western Mississippi and Texas. Our 11 largest fields (listed below) constitute approximately 90% of our total proved reserves on a BOE basis and 89% on a PV-10 Value basis. Within these 11 fields, we own a weighted average 89% 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 two primary field offices in Houma, Louisiana, and Laurel, Mississippi.

	PROVED RESERVES AS OF DECEMBER 31, 2004 (1)					AVERAGE DAILY PRODUCTION (2)		
	OIL (MBBLS)	NATURAL GAS (MMCF)	MBOE'S	BOE % OF TOTAL	PV-10 VALUE (000'S)	OIL (BBLS/D)	NATURAL GAS (MCF/D)	AVERAGE NET REVENUE INTEREST
MISSISSIPPI – CO_2 FLOODS								
Brookhaven	18,707	—	18,707	14.5%	$ 185,962	—	—	80.7%
Mallalieu (East & West)	14,888	—	14,888	11.5%	316,010	3,351	—	80.6%
McComb/Olive	10,666	—	10,666	8.2%	158,583	285	—	75.1%
Little Creek & Lazy Creek	6,271	—	6,271	4.8%	122,320	3,148	—	83.2%
Total Mississippi – CO_2 floods	50,532	—	50,532	39.0%	782,875	6,784	—	79.7%
OTHER MISSISSIPPI								
Heidelberg (East & West)	32,577	56,575	42,006	32.5%	364,656	5,476	13,794	76.9%
Eucutta	4,485	—	4,485	3.5%	42,391	1,162	—	65.7%
King Bee	2,203	—	2,203	1.7%	22,126	460	—	79.9%
Brookhaven (non-CO_2)	1,515	—	1,515	1.2%	25,718	380	—	76.7%
Other Mississippi	8,047	6,728	9,168	7.1%	98,483	2,991	1,898	10.2%
Total Other Mississippi	48,827	63,303	59,377	46.0%	553,374	10,469	15,692	38.1%
LOUISIANA								
Lirette	97	7,029	1,269	1.0%	31,778	300	13,704	61.6%
S. Chauvin	372	11,169	2,234	1.7%	47,485	141	3,522	38.7%
Thornwell	411	6,061	1,421	1.1%	37,437	259	7,367	35.0%
Other Louisiana	1,048	18,627	4,153	3.2%	90,411	847	11,906	39.9%
Total Louisiana	1,928	42,886	9,077	7.0%	207,111	1,547	36,499	40.7%
TEXAS								
Newark (Barnett Shale)	—	62,295	10,383	8.0%	99,929	127	2,754	63.1%
COMPANY TOTAL	101,287	168,484	129,369	100.0%	$1,643,289	18,927	54,945	51.5%

(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, 2004. The prices at that date were a NYMEX oil price of $43.45 per Bbl adjusted to prices received by field and a NYMEX natural gas price average of $6.15 per MMBtu also adjusted to prices received by field.

(2) Does not include production on the Company's offshore properties sold in July 2004. The total average annual production on these properties for 2004 was 319 Bbls/d and 27.3 MMcf/d.

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, 2004:

	DEVELOPED		UNDEVELOPED		TOTAL	
	GROSS	NET	GROSS	NET	GROSS	NET
Louisiana	39,867	31,214	25,686	19,440	65,553	50,654
Mississippi	92,038	71,416	256,734	36,647	348,772	108,063
Texas, other	15,353	10,043	92,478	18,855	107,831	28,898
Total	147,258	112,673	374,898	74,942	522,156	187,615

Denbury's net undeveloped acreage that is subject to expiration over the next three years is approximately 7% in 2005, 11% in 2006 and 9% in 2007.

PRODUCTIVE WELLS

The following table sets forth our gross and net productive oil and natural gas wells at December 31, 2004:

	PRODUCING OIL WELLS		PRODUCING NATURAL GAS WELLS		TOTAL	
	GROSS	NET	GROSS	NET	GROSS	NET
OPERATED WELLS:						
Louisiana	32	25.7	39	30.9	71	56.6
Mississippi	441	422.0	104	94.1	545	516.1
Offshore Gulf Coast	—	—	—	—	—	—
Texas, other	—	—	18	17.0	18	17.0
Total	473	447.7	161	142.0	634	589.7
NON-OPERATED WELLS:						
Louisiana	—	—	13	3.4	13	3.4
Mississippi	24	2.4	17	5.2	41	7.6
Offshore Gulf Coast	—	—	1	0.8	1	0.8
Texas, other	—	—	11	2.8	11	2.8
Total	24	2.4	42	12.2	66	14.6
TOTAL WELLS:						
Louisiana	32	25.7	52	34.3	84	60.0
Mississippi	465	424.4	121	99.3	586	523.7
Offshore Gulf Coast	—	—	1	0.8	1	0.8
Texas, other	—	—	29	19.8	29	19.8
Total	497	450.1	203	154.2	700	604.3

DRILLING ACTIVITY

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

	YEAR ENDED DECEMBER 31,					
	2004		2003		2002	
YEAR ENDED DECEMBER 31,	GROSS	NET	GROSS	NET	GROSS	NET
EXPLORATORY WELLS: (1)						
Productive (2)	8	5.8	7	5.3	7	4.9
Non-productive (3)	4	2.3	7	4.8	4	3.2
DEVELOPMENT WELLS: (1)						
Productive (2)	68	53.8	37	31.3	33	27.1
Non-productive (3)(4)	1	0.6	3	1.2	2	1.9
Total	81	62.5	54	42.6	46	37.1

(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 development well is a well drilled within the presently proved productive area of an oil or natural gas reservoir, as indicated by reasonable interpretation of available data, with the objective of completing in that reservoir.*

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

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

(4) *During 2004, 2003 and 2002, an additional 8, 5, and 9 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, 2004, we had two purchasers that each accounted for 10% or more of our oil and natural gas revenues: Hunt Refining (21%) and Genesis Energy, L.P. (14%). For the year ended December 31, 2003, two purchasers each accounted for more than 10% of our total oil and natural gas revenues: Hunt Refining (15%) and Genesis Energy, L.P. (12%). For the year ended December 31, 2002, two purchasers each accounted for 10% or more of our oil and natural gas revenues: Hunt Refining (14%) and Genesis Energy, L.P. (11%).

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, our single largest field, 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, our current CO_2 operations, and in Louisiana, 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, 2004, the discount for our oil production from Heidelberg Field averaged $9.80 per Bbl and for our Eastern Mississippi properties as a whole the discount averaged $8.84 per Bbl relative to NYMEX oil prices. For Mallalieu Field, the largest producer during 2004 of our CO_2 properties in Western Mississippi, we averaged a premium of $1.20 per Bbl over NYMEX oil prices, and $1.13 per Bbl over NYMEX prices for our tertiary oil production in Western Mississippi taken as a whole. Our Louisiana properties averaged $2.39 per Bbl below NYMEX prices during 2004.

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.

Operating Environment Risk Factors

OIL AND NATURAL GAS PRICE VOLATILITY

Our future financial condition, results of operations and the carrying value of our oil and natural gas properties depends 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. In the short-term, our production is relatively balanced between oil and natural gas, but long-term, oil prices are likely to affect us more than natural gas prices because approximately 78% of our proved reserves are oil. 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;
- 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 2004, NYMEX oil prices were high throughout the year, averaging over $41.00 per Bbl, ending the year at $43.45 per Bbl. During 2004, 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 the fourth quarter, averaging $6.48 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 have as much of an impact on our profitability as does the volatility in the NYMEX oil prices.

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. For 2004, NYMEX natural gas prices averaged over $6.00 per MMBtu, ending the year at $6.15 per MMBtu.

PRODUCT PRICE DERIVATIVE HEDGING CONTRACTS

To reduce our exposure to fluctuations in the prices of oil and natural gas, we currently and may in the future enter into hedging arrangements for a portion of our oil and natural gas production. Hedging arrangements expose us to risk of financial loss in some circumstances, including when:

- production is less than expected;
- the counter-party to the hedging contract defaults on its contract obligations (as was the case with respect to our hedges placed in 2001 with an Enron subsidiary as counterparty, which resulted in our suffering a loss); or
- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

In addition, these hedging arrangements 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 9, "Derivative Hedging Contracts," to the Consolidated Financial Statements.

OIL AND NATURAL GAS DRILLING AND PRODUCING OPERATIONS

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;
- 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.

In accordance with industry practice, we maintain insurance against some, but not all, of the risks described above in an amount we believe is adequate. However, the nature of these risks is such that some liabilities could exceed our 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.

USE OF CARBON DIOXIDE IN TERTIARY RECOVERY OPERATIONS

The crude oil production from our tertiary recovery projects depends on having access to sufficient amounts of carbon dioxide. Our ability to produce this oil would be hindered if our supply of carbon dioxide were limited due to problems with our current CO_2 producing wells and facilities, including compression equipment, or catastrophic pipeline failure. Our anticipated future production is also dependent on our ability to increase the production volumes of CO_2. If our crude oil production were to decline, it could have a material adverse effect on our financial condition and results of operations. 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 a material adverse effect upon the profitability of these operations.

FUTURE PERFORMANCE AND ACQUISITIONS

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. In addition, 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.

We are continually identifying and evaluating acquisition opportunities and we have successfully completed acquisitions throughout our history. Estimating the reserves and forecasted production from acquired properties is inherently difficult and may result in our inability to achieve or maintain targeted production levels. In that case, our ability to realize the total economic benefit from the acquisition may be reduced or eliminated. There can be no assurance that we will successfully consummate any future acquisitions or that such acquisitions of oil and natural gas properties will contain economically recoverable reserves or that any future acquisition will be profitably integrated into our operations.

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 long-lived, high margin nature of our oil and gas reserves and management's experience and expertise in exploiting these reserves, 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 which 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 which 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, 2004, 2003 and 2002. 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 non-producing reserves.

Proved undeveloped reserves associated with our CO_2 tertiary operations in West Mississippi and our Heidelberg waterfloods in East Mississippi account for approximately 96% 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 in Newark, East fields account for approximately 87% of our proved undeveloped natural gas reserves. The remaining undeveloped natural gas reserves are spread over multiple fields with the single largest field accounting for less than 5% of the total undeveloped natural gas reserves. This particular field's undeveloped reserves are currently being developed with first production expected late in the first quarter of 2005. Our current plans for 2005 include development of 20 to 25 wells in each of our primary natural gas plays, the Barnett Shale and Selma Chalk.

	DECEMBER 31,		
	2004	2003	2002
ESTIMATED PROVED RESERVES:			
Oil (MBbls)	101,287	91,266	97,203
Natural gas (MMcf)	168,484	221,887	200,947
Oil equivalent (MBOE)	129,369	128,247	130,694
PERCENTAGE OF TOTAL MBOE:			
Proved producing	39%	43%	43%
Proved non-producing	16%	18%	23%
Proved undeveloped	45%	39%	34%
REPRESENTATIVE OIL AND GAS PRICES: (1)			
Oil – NYMEX	$ 43.45	$ 32.52	$ 31.20
Natural gas – NYMEX Henry Hub	6.15	6.19	4.79
PRESENT VALUES: (2)			
Discounted estimated future net cash flow before income taxes ("PV-10 Value")(thousands)	$1,643,289	$1,566,371	$1,426,220
Standardized measure of discounted estimated future net cash flow after income taxes (thousands)	1,129,196	1,124,127	1,028,976

(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 NYMEX Henry Hub 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. The reserve data included herein represents only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available geological, geophysical, engineering and economic data, the precision of the engineering and judgment. As a result, estimates of different engineers often vary. The estimates of reserves, future cash flows and present value are based on various assumptions, including those prescribed by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds, and are inherently imprecise. Actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from our estimates. Such variations may be significant and could materially affect estimated quantities and the present value of our proved reserves. Also, the use of a 10% discount factor for reporting purposes may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which Denbury or the oil and natural gas industry in general are subject. See also Note 13, "Supplemental Oil and Natural Gas Disclosures," to the Consolidated Financial Statements.

You should not assume that the present values referred to herein represent the current market value of our estimated oil and natural gas reserves. 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 costs as of the date of the estimate.

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.

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 10, "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, including those noted below. 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. The estimate of the potential impact from the following legal proceedings on our financial position or overall results of operations could change in the future.

Along with two other companies, we have been named in a lawsuit styled *J. Paulin Duhe, Inc. vs. Texaco, Inc., et al*, Cause No. 101,227, filed in late 2003 in the 16th Judicial District Court, Division "E," Terrebonne Parish, Louisiana, seeking restoration to its original condition of property on which oil has been produced over the past 70 years. The contract and tort claims by the plaintiffs allege surface and groundwater damage of 26 acres that are part of our Iberia Field in Iberia Parish, Louisiana. Recently, plaintiff's experts have initially alleged that clean-up of alleged contamination of the property would cost $79.0 million, although settlement offers by plaintiffs have already been made for much smaller sums. The property was originally leased to Texaco, Inc. for mineral development in 1934 and Denbury acquired its interest in the property in August 2000 from Manti Operating Company. Discovery is currently underway, and the April 2005 trial setting has been continued to an unspecified date in the future. We believe that we are indemnified by the prior owner, which we expect to cover our exposure to most damages, if any, found to have occurred prior to the time that we purchased the property. We believe that the allegations of this lawsuit are subject to a number of defenses, are without merit and we and the other defendants plan to vigorously defend this lawsuit, and if necessary, we will seek indemnification from the prior owner.

On December 29, 2003, an action styled *Harry Bourg Corporation vs. Exxon Mobil Corporation, et al*, Cause No. 140749, was filed in the 32nd Judicial District Court, Terrebonne Parish, Louisiana against Denbury and eleven other oil companies and their predecessors alleging damage as the result of mineral exploration activities conducted by these oil and gas operators/companies over the last 60 years. Plaintiff has asked for restoration of the 10,000 acre property and/or damages in claims made under tort law and various oil and gas contracts. The Bourg Corporation recently produced its first preliminary expert reports that allege damages of approximately $100.0 million against Denbury. Discovery is continuing in this case, with trial currently set for January 2006. We believe the allegations of this lawsuit are without merit and plan to vigorously defend this lawsuit along with the other defendants. No provision has been accrued in our financial statements.

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 2004.

PART II

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

Common Stock Trading Summary

The following table summarizes the high and low reported sales prices on days in which there were trades of Denbury's common stock on the New York Stock Exchange ("NYSE"), for each quarterly period for the last two fiscal years. As of February 28, 2005, to the best of our knowledge, Denbury's common stock was held of record by approximately 8,000 holders. On February 28, 2005, the last reported sales price of Denbury's Common Stock, as reported on the NYSE, was $32.90 per share.

	2004		2003	
	High	Low	High	Low
First Quarter	$ 16.93	$13.26	$ 11.59	$10.18
Second Quarter	21.73	16.72	13.86	10.25
Third Quarter	26.20	18.59	13.95	11.65
Fourth Quarter	29.30	24.05	14.24	11.23
Annual	$29.30	$13.26	$14.24	$10.18

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 2004.

Equity Compensation Plan Information

The following table summarizes information about Denbury's equity compensation plans as of December 31, 2004.

PLAN CATEGORY	NUMBER OF SECURITIES TO BE ISSUED UPON EXERCISE OF OUTSTANDING OPTIONS, WARRANTS AND RIGHTS (A)	WEIGHTED AVERAGE EXERCISE PRICE OF OUTSTANDING OPTIONS, WARRANTS AND RIGHTS (B)	NUMBER OF SECURITIES REMAINING AVAILABLE FOR FUTURE ISSUANCE UNDER EQUITY COMPENSATION PLANS (EXCLUDING SECURITIES REFLECTED IN COLUMN A) (C)
EQUITY COMPENSATION PLANS APPROVED BY SECURITY HOLDERS:			
Stock Option Plan	4,440,157	$10.49	710,291
2004 Omnibus Plan	—	—	1,350,000
Employee Stock Purchase Plan	—	—	291,376
EQUITY COMPENSATION PLANS NOT APPROVED BY SECURITY HOLDERS:			
Director Compensation Plan	—	—	71,930
	4,440,157	$10.49	2,423,597

Our Director Compensation Plan was adopted effective July 1, 2000 for a term of ten years. The Director Plan allows each non-employee director to make an annual election to receive his or her compensation in either cash or in shares of our common stock and to elect to defer receipt of such compensation, if they wish. We anticipate that the Director Plan will be modified in 2005 to no longer allow directors to defer receipt of such compensation due to the American Jobs Creation Act of 2004. The number of shares issued to a director who elects to receive shares of common stock under the Director Plan is calculated by dividing the director fees to be paid to such director by the average price of the Company's common stock for the ten trading days prior to the date the fees are payable. Generally director's fees are paid quarterly. We have reserved 100,000 shares for issuance under the Director Plan, for directors who elect to receive their compensation in stock.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table summarizes the Company's purchases of stock in the open market during the three months ended December 31, 2004:

	Issuer Purchases of Equity Securities			
PERIOD	(A) TOTAL NUMBER OF SHARES PURCHASED	(B) AVERAGE PRICE PAID PER SHARE	(C) TOTAL NUMBER OF SHARES PURCHASED AS PART OF PUBLICLY ANNOUNCED PLANS OR PROGRAMS	(D) MAXIMUM NUMBER OF SHARES THAT MAY YET BE PURCHASED UNDER THE PLAN OR PROGRAMS
October 2004	50,000	$25.28	50,000	100,000
November 2004	—	—	—	100,000
December 2004	—	—	—	100,000
Total	50,000	$25.28	50,000	100,000

In August 2003, we adopted a stock repurchase plan (the "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. The Plan originally provided for purchases through an independent broker of 50,000 shares of Denbury's common stock per fiscal quarter for a period of approximately twelve months, or a total of 200,000 shares, beginning August 13, 2003 and ending on July 31, 2004. In May 2004, the Board of Directors renewed the Plan for another year beginning July 1, 2004 and ending June 30, 2005, covering another 200,000 shares at the same 50,000 shares per quarter rate. Purchases are to be made at prices and times determined at the discretion of the independent broker, provided however that no purchases may be made during the last ten business days of a fiscal quarter.

ITEM 6. SELECTED FINANCIAL DATA

	YEAR ENDED DECEMBER 31,				
(IN THOUSANDS, UNLESS OTHERWISE NOTED)	2004 [1]	2003	2002	2001 [1]	2000
CONSOLIDATED STATEMENTS OF OPERATIONS DATA:					
Revenues	$382,972	$ 333,014	$ 285,152	$ 285,111	$ 181,651
Net income	82,448	56,553 [2]	46,795	56,550	142,227 [3]
Net income per common share:					
Basic	1.50	1.05 [2]	0.88	1.15	3.10
Diluted	1.44	1.02 [2]	0.86	1.12	3.07
Weighted average number of common shares outstanding:					
Basic	54,871	53,881	53,243	49,325	45,823
Diluted	57,301	55,464	54,365	50,361	46,352
CONSOLIDATED STATEMENTS OF CASH FLOW DATA:					
Cash provided by (used by):					
Operating activities	$ 168,652	$197,615	$159,600	$185,047	$95,972
Investing activities	(71,700)	(135,878)	(171,161)	(318,830)	(133,040)
Financing activities	(66,251)	(61,489)	12,005	134,986	47,593
PRODUCTION (DAILY):					
Oil (Bbls)	19,247	18,894	18,833	16,978	15,219
Natural gas (Mcf)	82,224	94,858	100,443	85,238	37,078
BOE (6:1)	32,951	34,704	35,573	31,185	21,399
UNIT SALES PRICE (EXCLUDING HEDGES):					
Oil (per Bbl)	$ 36.46	$ 27.47	$ 22.36	$ 21.34	$ 25.89
Natural gas (per Mcf)	6.24	5.66	3.31	4.12	4.45
UNIT SALES PRICE (INCLUDING HEDGES):					
Oil (per Bbl)	$ 27.36	$ 24.52	$ 22.27	$ 21.65	$ 23.50
Natural gas (per Mcf)	5.57	4.45	3.35	4.66	3.57
COSTS PER BOE:					
Lease operations	$ 7.22	$ 7.06	$ 5.48	$ 4.84	$ 4.94
Production and severance taxes	1.55	1.17	0.92	0.96	1.02
General and administrative	1.78	1.20	0.96	0.89	1.09
Depletion, depreciation, and amortization	8.09	7.48	7.26	6.27	4.62
PROVED RESERVES:					
Oil (MBbls)	101,287	91,266	97,203	76,490	70,667
Natural gas (MMcf)	168,484	221,887	200,947	198,277	100,550
MBOE (6:1)	129,369	128,247	130,694	109,536	87,425
CONSOLIDATED BALANCE SHEET DATA:					
Total assets	$992,706	$ 982,621	$895,292	$ 789,988	$ 457,379
Total long-term liabilities	368,128	434,845	432,616	360,882	202,428
Stockholders' equity [4]	541,672	421,202	366,797	349,168	216,165

(1) We sold Denbury Offshore, Inc. in July 2004. We acquired Matrix Oil and Gas Inc. in July 2001.

(2) 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 $0.05.

(3) In 2000, we recorded a deferred income tax benefit of $67.9 million related to the reversal of the valuation allowance on our net deferred tax assets.

(4) 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 reserves of carbon dioxide ("CO_2") used for tertiary oil recovery east of the Mississippi River, and hold significant operating acreage onshore Louisiana and in the Barnett Shale play in 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 two primary field offices located in Houma, Louisiana, and Laurel, Mississippi.

Overview

Continued expansion of our tertiary operations. Since we acquired our first carbon dioxide tertiary flood in Mississippi over five years ago, 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" for further information regarding these operations, their potential, and the ramifications of this change in focus.

During the last few years, we have gradually increased the percentage of our spending dedicated to CO_2 and tertiary related operations. During 2002 and 2003, we spent around 25% of our capital budget on tertiary related items, spent approximately 46% during 2004, and we further emphasized this part of our business by budgeting over 60% of our initial 2005 capital budget for tertiary operations. We plan to spend approximately $190 million during 2005 on tertiary operations, including an estimated $45 million for an 84-mile pipeline to transport CO_2 from our CO_2 source fields located near Jackson, Mississippi to our planned tertiary recovery operations in East Mississippi, an expenditure that may ultimately be financed with sources other than our cash flow. We anticipate that the pipeline will be ready for use during the first half of 2006 to commence what we call Phase II (operations in East Mississippi) of our tertiary recovery program (see "CO_2 Operations"). Phase II will initially consist of tertiary recovery operations at six oil fields in that region, but we ultimately plan to expand these operations to several other oil fields in the area, which would also be serviced by the new pipeline. Our focus on CO_2 tertiary related operations is expected to impact our financial results and certain operating statistics. See "Results of Operations – CO_2 Operations – Financial Statement Impact of CO_2 Operations" below.

During 2004, we drilled four CO_2 wells which added an estimated 1.0 Tcf of proved CO_2 reserves, resulting in total proved CO_2 reserves at December 31, 2004 of approximately 2.7 Tcf (2.1 Tcf to our net ownership – see "CO_2 Operations – CO_2 Resources"). We anticipate that year-end 2004 proved CO_2 reserves will be sufficient to satisfy the projected CO_2 requirements for our first two tertiary operation phases, Phase I, our tertiary operations in Southwest Mississippi, and Phase II, our recently planned expansion into Eastern Mississippi.

Following the sale of our offshore operations in July 2004, we updated our development schedule and targeted oil production from these tertiary recovery operations. Based on our current plans, we anticipate that we can continue to show significant growth in our oil production from tertiary operations for the next five to ten years from our planned Phase I and Phase II operations. The model assumes that the first production from tertiary recovery operations in Eastern Mississippi will occur in 2007. During 2004, oil production from our tertiary recovery operations averaged 6,784 BOE/d, averaging 7,242 BOE/d during the fourth quarter.

Sale of offshore operations. 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

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

less operating expenses and capital expenditures) from these properties which we received between April 1st and closing, as well as expenses of the sale and other contractual adjustments, reduced the purchase price to approximately $187 million. The purchaser also received the net working capital of Denbury Offshore as of the closing date, which primarily consisted of accrued production receivables.

We excluded two significant items from the sale: (i) a discovery well drilled at High Island A-6 during 2004 and (ii) certain deep rights at West Delta 27. The well at High Island A-6 should be on production during the first half of 2005, and we sold a substantial portion of the deep rights at West Delta 27 during the third quarter of 2004 for $1.8 million but retained a carried interest in a deep exploratory well.

Our offshore properties made up approximately 12% of our year-end 2003 proved reserves (approximately 96 Bcfe as of December 31, 2003) and represented approximately 25% (9,114 BOE/d) of our 2004 second quarter production.

Operating results. As a result of the sale of our offshore properties early in the third quarter of 2004, our total production was significantly reduced, contributing to a 5% decline in production levels during 2004 as compared to 2003 levels. However, higher commodity prices more than offset the lower production, resulting in net income of $82.4 million during 2004 as compared to $56.6 million of net income during 2003. The increase in adjusted cash flow from operations during 2004 was less significant (5%) primarily due to the $21.0 million of income taxes paid relating to the sale of our offshore properties. See "Results of Operations – Operating Income" for discussion of this non-GAAP measure versus cash flow from operations, which decreased by 15% between the two periods. Payments on our commodity hedges continued to be a significant outflow, totaling $84.6 million for 2004, up from $62.2 million during 2003. Hedge payments should drop significantly during 2005 as most of our out-of-the-money hedges expired at December 31, 2004. See "Results of Operations" for a more thorough discussion of our operating results and "Market Risk Management" for more information regarding our hedge position at year-end 2004 and our new method of accounting for hedges for 2005.

Capital Resources and Liquidity

For 2005, our initial capital budget, excluding any potential acquisitions, is $305 million, which at commodity futures prices as of the end of February 2005 will be slightly more than anticipated cash flow from operations. That budget includes an estimated $45 million for a CO_2 pipeline being constructed to East Mississippi (see "Expansion of our tertiary operations" under "Overview" above), which we may refinance upon completion by entering into some sort of long-term financing, effectively paying for the cost of the pipeline over time and recouping the cash spent. 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 often increased our capital budget during the year and would likely do so again if commodity prices remain strong or increase further.

At year-end 2004, we had approximately $70 million in cash and short-term investments remaining from the sale of our offshore properties, over and above our normal month-end cash balances. We plan to invest this remaining cash and any cash potentially generated from operations in excess of our capital budget (such amount being highly dependent on commodity prices) over the next one to two years on property acquisitions, particularly those that have future tertiary potential. Although we now control most of the fields along our existing CO_2 pipeline, there are several fields in East Mississippi that could be acquired to expand our planned tertiary operations there, plus we are continuing to seek additional interests in the fields that we currently own. Further, we would like to add additional phases or areas of tertiary operations by acquiring other old oil fields in other parts of our region of operations, building a CO_2 pipeline to those areas and initiating additional tertiary floods. We accelerated the pace and expenditures on our tertiary operations following the offshore sale, and

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plan to continue to do so as long as it remains economic and practical. We also may seek conventional development and exploration projects in our areas of operations or tertiary operations in other areas of the country. In addition to our cash and short-term investments which may be used for the potential aforementioned projects, we have all of our bank credit line available to us if we were to need additional capital.

At December 31, 2004, we had outstanding $225 million (principal amount) of 7.5% subordinated notes due in 2013, approximately $4 million of capital lease commitments, no bank debt, and working capital of $90 million. On September 1, 2004, we amended and restated our bank credit agreement which modified the prior agreement by (i) creating a structure wherein the commitment amount and borrowing base amount are no longer the same, (ii) improving our credit pricing by reducing the interest rate chargeable at certain levels of borrowing, (iii) extending the term by three years to April 30, 2009, (iv) reducing the collateral requirements, (v) authorizing up to $20 million of possible future CO_2 volumetric production payment transactions with Genesis Energy ($4.8 million of such transactions occurred in October 2004), and (vi) other minor modifications and corrections. Under the new agreement, our borrowing base was initially set at $200 million, a $25 million increase over the prior borrowing base of $175 million, with an initial commitment amount of $100 million. The borrowing base represents the amount we can borrow from a credit standpoint based on our assets, as confirmed by the banks, while the commitment amount is the amount we have asked the banks to commit to fund pursuant to the terms of the credit agreement. The banks have the option to participate in any borrowing request made by us in excess of the commitment amount, up to the borrowing base limit, although they are not obligated to fund any amount in excess of $100 million, the commitment amount. The advantage to us is that we will pay commitment fees on the lower commitment amount, not the higher borrowing base, thus lowering our overall cost of available credit.

SOURCES AND USES OF CAPITAL RESOURCES

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 Energy, L.P. ("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.

During 2003, we generated approximately $197.6 million of cash flow from operations and generated an additional $29.4 million of cash from sales of oil and gas properties. The largest single asset sale was the sale of Laurel Field, acquired from COHO in August 2002, which netted us approximately $25.9 million. Later in the year, we also sold a volumetric production payment to Genesis, which netted us approximately $23.9 million of cash. During 2003, we spent $146.6 million on oil and natural gas exploration and development expenditures, $22.7 million on CO_2 capital investments and acquisitions, and approximately $11.8 million on oil and natural gas property acquisitions, for total capital expenditures of approximately $181.1 million. Our exploration and development expenditures included approximately $115.3 million spent on drilling, $15.7

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

million of geological, geophysical and acreage expenditures and $35.2 million spent on facilities and recompletion costs. In addition, during 2003 we incurred approximately $15.6 million of costs for our subordinated debt refinancing. The $147.3 million of net total expenditures (including the $15.6 million of debt refinancing costs but net of property sales proceeds) was funded by our cash flow from operations, with the balance used to reduce our total debt by approximately $50.0 million.

During 2002, we spent approximately $99.3 million on exploration and development activities, approximately $56.4 million on acquisitions (the largest being the $48.2 million acquisition of the COHO properties), and approximately $16.4 million on CO_2 related capital expenditures, for a total of approximately $172.1 million. Our exploration and development expenditures included approximately $62.3 million spent on drilling, $17.8 million of geological, geophysical and acreage expenditures and $19.1 million spent on facilities and recompletion costs. The exploration and development expenditures were funded by cash flow from operations, and the acquisitions were primarily funded by cash flow, supplemented by property dispositions totaling $7.7 million and incremental bank debt for the year of $9.1 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 obligations that are not on our balance sheet include our operating leases, which at year-end 2004 totaled $21.6 million relating primarily to the lease financing of certain equipment for our CO_2 recycling facilities at our tertiary oil fields. We also have several leases relating to office space and other minor equipment leases. We also 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."

At December 31, 2004, we had a total of $460,000 outstanding in letters of credit. Genesis Energy, Inc., our 100% owned subsidiary which is the general partner of Genesis, has guaranteed the bank debt of Genesis, which consists of $15.3 million of debt and $22.8 million in letters of credit at December 31, 2004. 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, 2004. We do not have any material transactions with related parties other than sales of production and transportation arrangements 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.

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A summary of our obligations is presented in the following table:

	PAYMENTS DUE BY PERIOD						
AMOUNTS IN THOUSANDS	TOTAL	2005	2006	2007	2008	2009	THEREAFTER
CONTRACTUAL OBLIGATIONS:							
Subordinated debt [a]	$225,000	$ —	$ —	$ —	$ —	$ —	$225,000
Estimated interest payments on Subordinated debt	143,438	16,875	16,875	16,875	16,875	16,875	59,063
Operating lease obligations	21,582	3,977	3,967	3,954	3,807	3,064	2,813
Capital lease obligations [b]	6,807	806	806	806	806	806	2,777
Capital expenditure obligations [c]	23,752	23,752	—	—	—	—	—
Other long-term liabilities reflected in our Consolidated Balance Sheet:							
Derivative liabilities [d]	4,196	4,196	—	—	—	—	—
OTHER CASH COMMITMENTS:							
Future development costs on proved reserves, net of capital obligations [e]	320,988	110,491	84,686	48,809	36,313	14,629	26,060
Asset retirement obligations [f]	52,073	2,197	3,016	958	1,593	398	43,911
Total	$ 797,836	$162,294	$109,350	$71,402	$59,394	$35,772	$ 359,624

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

(b) Represents future minimum cash commitments under capital leases in place at December 31, 2004, primarily for transportation of crude oil and CO_2. Agreements are with Genesis. Approximately $2.2 million of these payments represents interest.

(c) Represents future minimum cash commitments under contracts in place as of December 31, 2004, 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 2005 is currently set at $305 million (including the CO_2 pipeline). 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 these types of 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 derivative obligations based on the futures market prices as of December 31, 2004. 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, 2004 was a $4.9 million liability. See further discussion of our derivative contracts in "Market Risk Management" contained in this Management's Discussion and Analysis of Financial Condition and in Note 9 to the Consolidated Financial Statements.

(e) Represents projected capital costs as scheduled in our December 31, 2004 proved reserve report that are necessary in order to recover our proved undeveloped reserves, but these are not current contractual commitments. Amount is net of capital obligations shown above.

(f) Represents the estimated future asset retirement obligations on an undiscounted basis. The discounted asset retirement obligation of $21.5 million, as determined under SFAS No. 143, is further discussed in Note 4 to the Consolidated Financial Statements.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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 two volumetric production payments ("VPP") contracts entered into during 2003 and 2004. Based upon the maximum amounts deliverable as stated in the contracts and the volumetric production payment, we estimate that we may be obligated to deliver up to 398 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 we project that our commitment would likely be reduced to approximately 332 Bcf. The maximum volume required in any given year is approximately 101 MMcf/d, although based on our current level of deliveries; this would likely be reduced to approximately 78 MMcf/d. Given the size of our proven CO_2 reserves at December 31, 2004 (approximately 2.7 Tcf before deducting approximately 178.7 Bcf for the two 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. Over five years ago we began our focus upon tertiary operations with the purchase of Little Creek Field, a tertiary recovery operation that was already underway. Subsequently, we have greatly expanded this program in Southwest Mississippi (Phase I of our tertiary operations), acquiring several more oil fields and most importantly the CO_2 resources used to flood these fields (see "CO_2 Resources" below). The focus has increased to the point that approximately 60% of our 2005 capital budget is dedicated to tertiary related operations, including the CO_2 pipeline currently under construction to East Mississippi (the area where we will conduct Phase II of our tertiary operations). We particularly like this play as (i) it is lower risk and more predictable than most traditional exploration and development activities, (ii) it provides a reasonable rate of return at relatively low oil prices (down to prices in the low twenties per Bbl in Phase I of our tertiary operations in Southwest Mississippi), 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.

CO_2 Resources. In February 2001, we acquired the sources of CO_2 located near Jackson, Mississippi, and a pipeline to transport it to our oil fields. Since February 2001, we have acquired two producing wells and drilled seven CO_2 producing wells, tripling our initial proven CO_2 reserves to 2.7 Tcf as of December 31, 2004 (including the 178.7 Bcf of reserves dedicated to two VPPs with Genesis). The estimate of 2.7 Tcf of proved CO_2 reserves is based on total CO_2 reserves in the fields, of which Denbury's net ownership is approximately 2.1 Tcf and is included in the evaluation of proven CO_2 reserves by DeGolyer & MacNaughton included as Exhibit 99. In discussing the available CO_2 reserves, 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. We currently estimate that it will take approximately 711 Bcf of CO_2 to develop and produce the proved tertiary recovery reserves we have recorded at December 31, 2004.

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 2005, we are capable of producing approximately 350 MMcf/d of CO_2, about four times the production capacity at the time of our initial acquisition of the Jackson Dome field. We continue to drill additional CO_2 wells, with four more wells planned for 2005, which are expected to further increase our production capacity and potentially increase our proven CO_2 reserves. We believe we have sufficient CO_2 reserves for our first two phases of tertiary operations in Western Mississippi and Eastern Mississippi, but would like to add additional reserves for

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future phases, plus we need to further increase our production capacity as our current model for phases I and II requires almost 700 MMcf/d of CO_2 production by 2009. Although we believe that our plans and projections are reasonable and achievable, there could be delays or unforeseen problems in the future which could delay our overall tertiary development program. We believe that such delays, if any, should only be temporary.

In addition to using CO_2 for our tertiary operations, we sell CO_2 to third party industrial users under long-term contracts. Our net operating margin from these sales was $6.2 million during 2002, $6.5 million during 2003, and $4.9 million during 2004. Our average CO_2 production during 2002, 2003 and 2004 was approximately 104 million, 170 million, and 218 million cubic feet per day, of which approximately 54% in 2002, 62% in 2003, and 73% in 2004 was used in our tertiary recovery operations, with the balance sold to third parties for industrial use.

We spent approximately $0.12 per Mcf to produce our CO_2 during 2004, slightly less than our 2003 annual average of $0.15 per Mcf, primarily due to the lack of any significant workover expenses like we had in 2003, partially offset by higher royalty expenses because certain of our royalties are adjusted based on oil prices. During 2002, we spent approximately $0.13 per Mcf to produce our CO_2. Our estimated total cost per thousand cubic feet of CO_2 during 2004 was approximately $0.21, after inclusion of depreciation and amortization expense related to the CO_2 production.

Oil Potential. Although our oil production from our CO_2 tertiary recovery activities is still relatively modest (approximately 25% of fourth quarter 2004 production), we expect it to be an ever increasing portion of our production. We currently have tertiary operations on-going at Little Creek, Mallalieu, McComb and Brookhaven Fields, as well as various smaller adjacent fields. We project that our oil production from these operations will increase substantially over the next several years, along with our tentatively scheduled tertiary projects at other oil fields along our pipeline. As of January 2005, these fields were producing approximately 8,300 Bbls/d. As of December 31, 2004, we had approximately 50.5 MMBbls of proven oil reserves related to tertiary operations in these fields along our CO_2 pipeline and have identified and estimated significant additional potential in fields that we own in this area. In addition, we have commenced operations to expand this program to East Mississippi and have commenced the acquisition of leases and right-of-way for the construction of an 84-mile CO_2 pipeline from our source wells near Jackson, Mississippi to Eucutta Field in East Mississippi. While our current tertiary operations in the Southwest part of Mississippi are economic at NYMEX per barrel oil prices in the low twenties, due predominately to the lower quality of oil in East Mississippi, we estimate that it requires a NYMEX oil price in the mid to upper twenties for the same rate of return in this part of the state. We believe that this expansion, labeled Phase II, has significant other oil potential well beyond the first six fields that we have engineered and currently plan to flood. Combining the production forecast for both of these areas extends the period during which we anticipate significant oil production growth from a few years, for Phase I alone, to five to ten years combined. While it is extremely difficult to accurately forecast 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 will be the backbone of our Company's growth for the foreseeable future.

Financial Statement Impact of CO_2 Operations. The increasing emphasis on CO_2 tertiary recovery projects has made, and will continue to make, an impact on our financial results and certain operating statistics different from conventional development activities.

First, there is a significant delay between the initial capital expenditures and the resulting production increases, as these tertiary operations require the building of facilities before CO_2 flooding can commence and it usually takes six-to-twelve months before the field responds (i.e. oil production commences) to the injection of CO_2. Further, as we expand to other areas beyond Phase I, there will be times when we spend significant amounts of capital before we can recognize any proven reserves as these other areas, for the most part, will require an oil production response to the CO_2 injections before any oil reserves can be recorded. We plan to spend over

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\$50 million on Phase II oil fields during 2005, plus an additional \$45 million on the CO_2 pipeline to East Mississippi.

Secondly, these tertiary projects are 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 liquid state for re-injection purposes). As commodity and energy prices increase, so does our operating expenses in these fields. As such, our overall operating expenses on a per BOE basis will likely continue to increase as these operations constitute an increasingly larger percentage of our operations. Our operating cost for our tertiary operations during 2004 averaged \$9.90 per BOE, as compared to an estimated cost of around \$5 to \$7 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. The CO_2 operating expenses allocated to our oil fields are recorded as lease operating expenses on those fields.

Third, all of our current CO_2 operations are in fields that produce light sweet oil and receive oil prices close to, and sometimes actually higher than, NYMEX prices. As this production becomes a larger percentage of our overall production, the overall average difference between the prices we receive and published NYMEX prices should decrease, assuming other market conditions do not change. While our oil prices have historically averaged between \$4.00 and \$5.00 below NYMEX prices, our 2002 average was \$3.74 below NYMEX and our 2003 average decreased further to \$3.60 below NYMEX. During 2004, the market for sour and heavy crude oil (predominately our East Mississippi production) deteriorated, causing our overall average differential to increase to \$4.91 per barrel for the year and to \$6.48 per barrel for the fourth quarter of 2004. While we cannot predict what will happen to the market for heavy and sour crude, we do expect our light sweet oil production to increase as a percentage of our total oil production over the next few years. However, this trend could reverse in future years as the anticipated oil production from Phase II of our tertiary operations is primarily heavy and sour oil.

2004 CO_2 Tertiary Recovery Operating Activities. Our oil production from our CO_2 tertiary recovery activities has steadily increased during the last few years, from 3,970 Bbls/d in 2002 to 4,671 Bbls/d during 2003, and to 6,784 Bbls/d during 2004, with a fourth quarter 2004 rate of 7,242 Bbls/d. This represents approximately 37% of our total corporate oil production during the fourth quarter of 2004 and approximately 25% of our total corporate production on a BOE basis. We expect that this oil production will continue to increase, although the increases are not always predictable or consistent.

While we did experience higher energy costs to operate our tertiary recycling facilities as a result of higher commodity prices, we were able to lower our operating cost per BOE in our tertiary operations from \$11.34 per BOE in 2003 to \$9.90 per BOE during 2004 because of the higher tertiary oil production levels. In addition to higher energy costs, we experienced general cost inflation in the industry and also commenced lease payments on certain of our recycling facilities (see "Commitments and Obligations" above). As a result, the absolute amount of operating expenses related to tertiary operations increased from \$14.3 million during 2002 to \$19.3 million during 2003 and \$24.6 million during 2004.

At December 31, 2004, we had proved reserves of 50.5 MMBbls relating to our tertiary recovery operations. Through December 31, 2004, we had spent a total of \$155.6 million on fields involved in this process, and had received \$160.0 million in net cash flow (revenue less operating expenses and capital expenditures), or net positive cash flow of \$4.4 million. The proved oil reserves in our CO_2 fields have a PV-10 Value of \$782.9 million, using December 31, 2004 constant NYMEX pricing of \$43.45 per Bbl. These amounts do not include the capital costs or related depreciation and amortization of our CO_2 producing properties. Through December 31, 2004, we have spent a total of \$132.8 million on our CO_2 producing properties, received a total of \$57.4 million in net cash flow (revenue less operating expenses and capital expenditures, consisting solely of sales to industrial customers and Genesis volumetric production payment receipts), leaving us a balance of approximately \$75.4 million of unrecovered costs for the CO_2 assets.

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CO_2 Related Capital Budget for 2005. Tentatively, we plan to spend approximately $35 million in 2005 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 2005 for our oil fields with tertiary operations in Southwest Mississippi and approximately $50 million for oil fields in East Mississippi, plus an additional $45 million for the CO_2 pipeline to East Mississippi, increasing our combined CO_2 related expenditures to over 60% of our 2005 capital budget.

OPERATING INCOME

Cash flow from operations and net income have been strong for the last three years, primarily because of higher than historical commodity prices. Production declined slightly (2%) from 2002 to 2003 and approximately 5% from 2003 to 2004, with most of the current year decrease related to the sale of our offshore properties (see also "Overview"). The higher commodity prices each year more than offset the production decline, resulting in higher overall net income and adjusted cash flow from operations each year from 2002 through 2004 (see discussion below regarding this non-GAAP measure, adjusted cash flow from operations).

AMOUNTS IN THOUSANDS EXCEPT PER SHARE AMOUNTS	YEAR ENDED DECEMBER 31, 2004	2003	2002
Net income	$ 82,448	$ 56,553	$ 46,795
Net income per common share:			
Basic	$1.50	$1.05	$0.88
Diluted	1.44	1.02	0.86
Adjusted cash flow from operations	$200,193	$189,802	$164,565
Net change in assets and liabilities relating to operations	(31,541)	7,813	(4,965)
Cash flow from operations (GAAP measure)	$168,652	$ 197,615	$159,600

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, as noted above, during 2003, our accounts payable and accrued liabilities increased as a result of our higher drilling activity level late in the year, particularly offshore, increasing our available cash from operations. 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, both of which contributed to the significant difference between our 2004 adjusted cash flow and GAAP cash flow from operations.

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

	YEAR ENDED DECEMBER 31,		
(IN THOUSANDS, EXCEPT PER BOE AMOUNTS)	2004	2003	2002
AVERAGE DAILY PRODUCTION VOLUME			
Bbls	19,247	18,894	18,833
Mcf	82,224	94,858	100,443
BOE [1]	32,951	34,704	35,573
OPERATING REVENUES			
Oil sales	$256,843	$189,442	$ 153,705
Natural gas sales	187,934	196,021	121,189
Total oil and natural gas sales	$444,777	$385,463	$274,894
HEDGE CONTRACTS			
Cash gain (loss) on effective hedge contracts	$ (70,469)	$ (62,210)	$ 932
Cash gain (loss) on ineffective hedge contracts	(14,088)	—	—
Total cash gain (loss)	(84,557)	(62,210)	932
Non-cash hedging adjustments	(1,270)	3,578	3,093
Total gain (loss) on derivative contracts	$ (85,827)	$ (58,632)	$ 4,025
OPERATING EXPENSES			
Lease operating expenses	$ 87,107	$ 89,439	$ 71,188
Production taxes and marketing expenses [3]	18,737	14,819	11,902
Total production expenses	$105,844	$104,258	$ 83,090
CO_2 sales and transportation fees [4]	$ 6,276	$ 8,188	$ 7,580
CO_2 operating expenses	1,338	1,710	1,400
CO_2 operating margin	$ 4,938	$ 6,478	$ 6,180
UNIT PRICES-INCLUDING IMPACT OF HEDGES [2]			
Oil price per Bbl	$ 27.36	$ 24.52	$ 22.27
Gas price per Mcf	5.57	4.45	3.35
UNIT PRICES-EXCLUDING IMPACT OF HEDGES [2]			
Oil price per Bbl	$ 36.46	$ 27.47	$ 22.36
Gas price per Mcf	6.24	5.66	3.31
OIL AND GAS OPERATING REVENUES AND EXPENSES PER BOE [1]			
Oil and natural gas revenues (including hedge settlements)	$ 29.87	$ 25.52	$ 21.24
Lease operating expenses	$ 7.22	$ 7.06	$ 5.48
Production taxes and marketing expenses	1.55	1.17	0.92
Total production expenses	$ 8.77	$ 8.23	$ 6.40

(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 hedging transactions.

(3) For 2004, includes transportation expenses paid to Genesis of $1.2 million.

(4) For 2004 and 2003, includes deferred revenue of $2,399,000 and $322,000, respectively, associated with volumetric production payments and transportation income of $2,694,000 and $355,000, respectively, both from Genesis.

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Production. Average daily production by area for 2002, 2003 and 2004, and each of the quarters of 2004 is listed in the following table (BOE/d).

	AVERAGE DAILY PRODUCTION (BOE/D)						
OPERATING AREA	2002	2003	FIRST QUARTER 2004	SECOND QUARTER 2004	THIRD QUARTER 2004	FOURTH QUARTER 2004	2004
Mississippi – non-CO_2 floods	13,378	13,638	12,754	13,048	12,969	13,564	13,085
Mississippi – CO_2 floods	3,970	4,671	6,318	6,603	6,967	7,242	6,784
Onshore Louisiana	8,050	8,222	8,825	7,492	7,033	7,182	7,630
Barnett Shale and other	200	224	229	345	803	963	587
Total production excl. offshore	25,598	26,755	28,126	27,488	27,772	28,951	28,086
Offshore Gulf of Mexico	9,975	7,949	8,521	9,114	1,885	26	4,865
Total Company	35,573	34,704	36,647	36,602	29,657	28,977	32,951

As a result of the sale of our offshore properties in July 2004, third and fourth quarter 2004 production decreased significantly from prior periods as listed in the above table. Adjusting for the offshore sale, overall production increased approximately 5% on a BOE/d basis during both 2003 and 2004, anchored by the increased production from our tertiary operations and Barnett Shale play, generally offset by overall declines in our onshore natural gas wells in Louisiana. However, other factors that caused fluctuations between the various periods should also be noted as outlined below.

The addition of properties acquired from COHO during August 2002 contributed to the majority of the increase in our overall production in the Mississippi-non-CO_2 flood properties from 2002 to 2003, as most of these pre-existing non-CO_2 fields in Mississippi have been on a slow decline as a result of normal depletion. Heidelberg Field, our single largest field that is located in this area, has partially offset this decline, as its production increased each year, from 7,479 BOE/d during 2002 to 7,535 BOE/d during 2003 to 7,775 BOE/d during 2004. Most of this increase at Heidelberg is attributable to additional natural gas drilling in the Selma Chalk formation as Heidelberg's oil production has been slowly decreasing. Natural gas production at this field averaged 7.1 MMcf/d in 2002, 10.3 MMcf/d in 2003 and 13.8 MMcf/d in 2004, making Heidelberg Field our single largest natural gas producing field during 2004.

As more fully discussed in "CO_2 Operations" above, oil production from our tertiary operations has increased each year.

Production from our offshore properties averaged 1,885 BOE/d in the third quarter, representing the production during the first 19 days of July prior to the sale. As evidenced in the above table, production from this area has fluctuated over the last three years primarily due to the level of activity and the fluctuations caused by the short-lived nature of these natural gas reserves. As an example, offshore production increased in early 2004 as a result of 15 well completions made late in the fourth quarter of 2003, four at Brazos A-21, three at North Padre A-9, three at Chandeleur Sound 69, two at West Cameron 192 and three at West Cameron 427. Some of our natural gas properties in onshore Louisiana have similar characteristics as is evident by the steep declines during 2004. While the production from onshore Louisiana only declined 7% on an annual basis, there was a 19% drop between the first quarter of 2004 and last quarter of 2004. A significant portion of this decline was at Thornwell Field, an onshore Louisiana field, which averaged 926 BOE/d during the fourth quarter of 2004, down from 2,526 BOE/d in the first quarter of 2004 and 2,487 BOE/d during 2003. Production from this field is in a steep decline due to its short-lived nature, and is expected to further decline in the future. In spite of its short remaining life, we have generated a good return on investment at Thornwell, generating $37.0 million of net positive cash flow (operating revenues less operating expenses and capital expenditures) through December 31, 2004, with a remaining PV-10 Value of $37.4 million as of December 31, 2004 (based on SEC proved reserve report at year-end 2004 prices).

Production in the Barnett Shale area has just recently begun to increase as a result of five horizontal wells drilled and completed in this area during the latter part of 2004. We plan to drill around 25 more wells there in 2005 and expect production from this area to further increase during 2005.

Our production for 2004 was weighted slightly toward oil (58%), although the fourth quarter 2004 average was 68% oil following the sale of the offshore properties in July 2004. It appears that we will remain similarly weighted toward oil in 2005 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. Two factors cause the change in pre-hedging revenues: commodity prices and production levels. Between 2003 and 2004, revenues increased by 15%, primarily due to higher commodity prices. The overall increase in commodity prices contributed $77.8 million in additional revenues, a 20% increase; partially offset by an overall decrease of $18.5 million (a 5% decrease) related to the 5% lower production volumes. Between 2002 and 2003, revenues increased by 40%, also primarily due to higher commodity prices. The overall increase in commodity prices contributed $117.3 million in additional revenues, a 43% increase; partially offset by an overall decrease in revenues of $6.7 million (a 2% decrease) related to the 2% lower production volumes.

During 2004, we paid out $64.1 million on our oil hedges ($9.10 per Bbl) and $20.4 million ($0.68 per Mcf) on our natural gas hedges relating to swaps and collars we purchased one to two years earlier when commodity prices were lower. About $30.5 million of the hedge payments related to swaps originally put in place to protect the rate of return for the COHO acquisition in August 2002. The payments in 2003 were similar in nature, but slightly less due to lower overall commodity prices. During 2003, we paid out $20.3 million on our oil hedges ($2.95 per Bbl) and $41.9 million ($1.21 per Mcf) on our natural gas hedges on generally the same swaps and collars. During 2002, we had total net receipts on our hedges of $932,000, paying out $0.6 million ($0.09 per Bbl) on our oil hedges, but collecting a net $1.5 million ($0.04 per Mcf) on our natural gas hedges. For 2005, we have hedged a lower percentage of our overall production, predominately with puts or price floors, so we anticipate that our hedge payments will be substantially lower than the payments made in 2004. See "Market Risk Management" for a further discussion of our hedging activities and position.

Our net oil and natural gas prices have fluctuated as outlined on the prior table. During 2004, we received the highest weighted average net price per BOE in our history, netting $29.87 per BOE even after paying out approximately $7.01 per BOE for hedge losses. This resulted from average NYMEX prices of over $41.00 per Bbl and $6.00 per MMBtu during the year. Prices were also strong during 2003, although not quite as high, netting Denbury $25.52 per BOE, net of the $4.91 per BOE hedge losses. During 2003 we also had one of our best years with regard to our realized net price relative to NYMEX prices. During 2002, we received an average discount to NYMEX of $3.74 per Bbl. This improved in 2003 to an average discount of $3.60 per Bbl. This trend was reversed in 2004 as the heavy, sour crude market (which predominately applies to our Eastern Mississippi production) deteriorated significantly, increasing our average oil differentials for the year to $4.91 per Bbl and $6.48 per Bbl for the fourth quarter of 2004. If market conditions for the heavy, sour crude remained consistent, we would expect to gradually improve the overall NYMEX discount as the amount of light sweet oil production from our tertiary operations is expected to increase, improving the overall quality of our product mix. However, as evident in 2004, the oil market can change substantially.

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Year over year, there is generally less fluctuation in our natural gas prices relative to NYMEX. Normally, we are at, or slightly above, the NYMEX market, primarily because of the high Btu content of our natural gas. For 2004, we had an average $0.02 premium to NYMEX, a little less than the $0.18 premium during 2003, but higher than the $0.05 discount in 2002. As we increase our emphasis on the Barnett Shale area in 2005, the overall price we receive for our natural gas could decline slightly as our properties in this area have historically received a price that is $0.50 to $0.75 less than NYMEX prices.

Operating Expenses. Lease operating expenses increased to $7.22 per BOE in 2004, a 2% increase over the $7.06 per BOE average during 2003, and an increase of 32% from the $5.48 per BOE average during 2002. During 2004, our workover expenses decreased as compared to 2003, when we spent $2.8 million on two individually significant workovers relating to mechanical failures of two onshore Louisiana wells, plus several smaller workovers. Operating expenses on our tertiary operations increased from $14.3 million during 2002 to $19.3 million in 2003 to $24.6 million in 2004 as a result of increased activity at Mallalieu and McComb Fields. However, with the 45% higher production from these tertiary operations between the same periods, operating expenses for our tertiary operations on a per BOE basis decreased from $11.34 per BOE in 2003 to $9.90 per BOE in 2004. Nonetheless, our tertiary operations are steadily increasing our aggregate dollar costs and our costs per BOE on a total corporate basis as our tertiary operations constitute a more significant portion of our total production and operations. The balance of cost increases during 2004 is generally attributable to higher energy costs to operate our tertiary recovery properties, a provision for potential litigation losses, and general cost inflation in our industry. In general, we expect our operating costs per BOE to further increase in the future as the operating costs of our tertiary operations are higher than the costs of our other operations.

Most of the increase from 2002 to 2003 was attributable to the aforementioned workovers, with several other smaller workovers, including one on a CO_2 well. The growth of our tertiary operations also contributed to an overall increase, as well as higher lease fuel costs and a full year of expenses on the properties acquired from COHO, which have typically had higher expenses on a per BOE basis than our other oil properties due to their age.

Production taxes and marketing expenses generally change in proportion to commodity prices and therefore, were higher in 2004 along with the record high commodity prices. The sale of our offshore properties also contributed to the increase in production taxes and marketing expenses on a per BOE basis during 2004, as most of our offshore properties were tax exempt.

GENERAL AND ADMINISTRATIVE EXPENSES

During the last three years, general and administrative ("G&A") expenses on a per BOE basis have increased from $0.96 per BOE during 2002, to $1.20 per BOE during 2003, to $1.78 per BOE during 2004, increasing even faster than the gross aggregate dollar increases in G&A expense as production has declined each year due primarily to property sales.

AMOUNTS IN THOUSANDS EXCEPT PER BOE AND EMPLOYEE DATA	YEAR ENDED DECEMBER 31, 2004	2003	2002
Gross G&A expense	$ 53,658	$ 46,031	$ 40,149
Operator overhead charges	(28,048)	(26,823)	(23,857)
Capitalized exploration expense	(5,072)	(5,507)	(5,325)
	20,538	13,701	10,967
State franchise taxes	923	1,488	1,459
Net G&A expense	$ 21,461	$ 15,189	$ 12,426
Average G&A expense per BOE	$ 1.78	$ 1.20	$ 0.96
Employees as of December 31	380	374	356

Gross G&A expenses increased $7.6 million, or 17%, between 2003 and 2004. The largest component of the increase was approximately $2.4 million of employee severance payments for the offshore professional and technical staff terminated in conjunction with our offshore property sale. We also incurred additional G&A expenses associated with our corporate restructuring in December 2003, compliance with the requirements of the

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Sarbanes-Oxley Act, the sale of stock by the Texas Pacific Group in March 2004, a provision for potential litigation losses, restricted stock grants, higher bonus levels for employees than in 2003 due to the strong performance during 2004, and overall increases in most other categories of G&A due to general cost inflation.

During the third and fourth quarters of 2004, we granted a total of 1,150,000 million shares of restricted stock to our officers and independent directors, generating deferred compensation expense of approximately $23.3 million, the market value of the shares on the date of grant. A portion of this restricted stock vests over five years and a smaller portion vests upon retirement (in addition to vesting upon death, disability or a change of control). We are amortizing the non-cash $23.3 million of compensation expense of this restricted stock over the five year vesting period and over the projected retirement date vesting period, expensing approximately $1.6 million during 2004. We estimate that amortized compensation expense for the restricted stock will be approximately $1.0 million per quarter through 2006.

Gross aggregate dollar G&A expenses increased $5.9 million, or 15%, between 2002 and 2003. The largest component of the increase was approximately $1.4 million of expenses spent for consultants hired to help document and test our system of internal controls, a requirement of the Sarbanes-Oxley Act of 2002. The second largest source of the increase was approximately $630,000 of legal, accounting, bank and other fees associated with the conversion to a holding company organizational structure during December 2003 which reduced our franchise taxes by $565,000 between 2003 and 2004. Other factors also contributed to the increase, the most significant being expenses associated with the sale of stock by the Texas Pacific Group in the first and last quarters of 2003, higher year-end expenses for engineering and audit fees, and an overall increase in personnel and associated expenses primarily related to cost of living salary increases. Partially offsetting these increases was a reduction in our 2003 bonuses due to less positive operating results during 2003 in certain areas.

Higher operator overhead recovery charges resulting from the 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, and drilling activity during the past year, the amount we recovered as operator overhead charges increased by 12% between 2002 and 2003 and 5% between 2003 and 2004. Capitalized exploration costs increased slightly between 2002 and 2003, along with increases in employee related costs, but decreased in 2004 as a result of the personnel reductions in our offshore area as a result of the property sale. The net effect of the increases in gross G&A expenses, operator overhead recoveries and capitalized exploration costs was a 41% increase in net G&A expense between 2003 and 2004 and a 22% increase between 2002 and 2003. The increase was even higher on a per BOE basis as a result of lower production, primarily related to the offshore property sale.

INTEREST AND FINANCING EXPENSES

AMOUNTS IN THOUSANDS EXCEPT PER BOE DATA	YEAR ENDED DECEMBER 31, 2004	2003	2002
Interest expense	$ 19,468	$ 23,201	$ 26,833
Non-cash interest expense	(962)	(1,251)	(2,659)
Cash interest expense	18,506	21,950	24,174
Interest and other income	(2,388)	(1,573)	(1,746)
Net cash interest expense	$ 16,118	$ 20,377	$ 22,428
Average net cash interest expense per BOE	$ 1.34	$ 1.61	$ 1.73
Average debt outstanding	$270,770	$341,496	$350,556
Average interest rate (1)	6.8%	6.4%	6.9%

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

Interest expense for 2004 decreased from 2003 primarily due to lower average debt levels as a result of our $50 million reduction in debt during 2003 and the payoff of our bank debt in the third quarter of 2004 with the proceeds from our offshore property sale. Our non-cash interest

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expense in 2004 decreased as a result of the subordinated debt refinancing in March 2003, which eliminated the amortization of discount on our old subordinated debt, which was higher than the discount and related amortization on our new subordinated debt issue. Interest and other income increased as a result of the cash generated from the offshore property sale.

Interest expense for 2003 decreased from levels in the prior year for similar reasons, (i) lower overall interest rates, resulting from an overall drop in market interest rates on our bank debt and due to the refinancing of our subordinated debt, (ii) lower average outstanding debt balance during 2003, as we reduced debt by $50 million during the year, and (iii) reduced debt issue cost amortization resulting from the complete amortization of costs associated with the original maturity of our bank credit line in December 2002 after we refinanced and extended the bank credit line to April 2006.

DEPLETION, DEPRECIATION AND AMORTIZATION ("DD&A")

AMOUNTS IN THOUSANDS, EXCEPT PER BOE DATA	YEAR ENDED DECEMBER 31, 2004	2003	2002
Depletion and depreciation of oil and natural gas properties	$88,505	$87,842	$87,728
Depletion and depreciation of CO_2 assets	4,664	2,542	1,858
Asset retirement obligations	2,408	2,852	2,951
Depreciation of other fixed assets	1,950	1,472	1,699
Total DD&A	$97,527	$94,708	$94,236
DD&A per BOE:			
Oil and natural gas properties	$ 7.54	$ 7.16	$ 6.98
CO_2 assets and other fixed assets	0.55	0.32	0.28
Total DD&A cost per BOE	$ 8.09	$ 7.48	$ 7.26

But for the property sales, our total proved reserve quantities would have increased each of the last three years. Our proved reserves decreased from 130.7 MMBOE as of December 31, 2002, to 128.2 MMBOE as of December 31, 2003 and increased slightly to 129.4 MMBOE as of December 31, 2004. During 2003 we sold approximately 8.3 MMBOE of proved reserves and during 2004 sold approximately 16.5 MMBOE of proved reserves, primarily related to the offshore sale. Reserve quantities and associated production are only one side of the DD&A equation, with capital expenditures, asset retirement obligations less related salvage value, and projected future development costs making up the remainder of the calculation.

In total, our DD&A rate on a per BOE basis increased 8% between 2003 and 2004, primarily due to the higher percentage of expenditures on offshore properties during 2003 and the first six months of 2004, which have higher overall finding and development costs, and an increase in certain of our future development cost estimates to reflect the rising costs in the industry. Although the 2004 average DD&A rate was similar to the DD&A rate of $8.00 per BOE during the fourth quarter of 2003, during the year there were significant fluctuations. Our DD&A rate on a per BOE basis decreased in the third quarter of 2004 to $7.62 per BOE from $8.46 per BOE in the second quarter, primarily as a result of the sale of our offshore properties, the proceeds of which were credited to the full cost pool. However, the rate increased in the fourth quarter of 2004 to $7.98 per BOE, primarily to reflect cost inflation in the industry, as we increased our cost estimates (i.e. future development costs) for certain existing proved undeveloped reserves. We adjust our DD&A rate each quarter based on any changes in our estimates of oil and natural gas reserves and costs, and thus our DD&A rate could change significantly in the future. Our DD&A rate for our CO_2 and other fixed assets increased in 2004 as a result of the additional cost incurred drilling CO_2 wells during the year and higher associated future development costs, partially offset by an increase in CO_2 reserves from 1.6 Tcf as of December 31, 2003 to 2.7 Tcf as of December 31, 2004 (100% working interest basis before amounts attributable to Genesis volumetric production payments – see "CO_2 Operations – CO_2 Resources").

During 2003, the fourth quarter DD&A rate increased to $8.00 per BOE, increasing the 2003 annual average to $7.48 per BOE. The higher DD&A was partially due to the higher percentage of capital expenditures

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spent on our offshore properties, 34% during 2003 as compared to approximately 10% during 2002, where we have a higher overall finding cost. The rate was also affected by less than hoped for drilling results in the Gulf of Mexico and Southern Louisiana, particularly in the fourth quarter, where some of our larger exploration potential failed to materialize. In contrast to our offshore properties, our tertiary operations have yielded a finding and development cost, including the net change in forecasted future development and abandonment costs, of just under $6.00 per BOE inception to December 31, 2004, in line with our long-term expectations, helping to partially offset the higher finding and development cost of our offshore and other natural gas properties.

Prior to 2003, we provided for the estimated future costs of well abandonment and site reclamation, net of any anticipated salvage, on a unit-of-production basis. This provision was included in DD&A expense and increased each year, along with a general increase in the number of our properties, especially the acquisition of our offshore properties. Effective January 1, 2003, we adopted Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recorded in the period in which it is incurred, discounted to its present value using our credit adjusted risk-free interest rate, and that a corresponding amount be 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. If the liability is settled for an amount other than the recorded amount, the difference is recorded to the full cost pool, unless significant. As part of this adoption, we ceased accruing for site reclamation costs, as had been our practice in the past, and recorded a $41.0 million liability representing the estimated present value of our retirement obligations, with a $34.4 million increase to oil and natural gas properties. On an undiscounted basis, we estimated our retirement obligations as of December 31, 2003 to be $82.7 million, with an estimated salvage value of $43.3 million, also on an undiscounted basis. As of December 31, 2004, we estimated our retirement obligations to be $52.1 million ($21.5 million present value), with an estimate salvage value of $43.6 million, the decrease related to the sale of our offshore properties. 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 2002, 2003 or 2004 and do not expect to have any such write downs in the foreseeable future at current commodity price levels.

INCOME TAXES

AMOUNTS IN THOUSANDS, EXCEPT PER BOE AMOUNTS	YEAR ENDED DECEMBER 31, 2004	2003	2002
Current income tax expense (benefit)	$ 22,929	$ (91)	$ (406)
Deferred income tax provision	16,463	26,303	23,926
Total income tax provision	$ 39,392	$ 26,212	$ 23,520
Average income tax provision per BOE	$3.27	$2.07	$1.81
Net effective tax rate	32.3%	32.7%	33.4%
Federal tax net operating loss carryforwards	$ —	$ 94,955	$ 84,891
Total net deferred tax asset (liability)	(71,936)	(43,539)	(21,777)

Our income tax provision for 2004 was increased to an estimated statutory tax rate of 39% to reflect the changes in our state income tax rates resulting from the sale of our offshore properties. Our tax provision for 2002 and 2003 was based on an estimated statutory rate of 38%. Our net effective tax rate for all periods was lower than the statutory rates, primarily due to the recognition of enhanced oil recovery credits which lowered our overall tax rate. The current income tax expense represents our anticipated alternative minimum cash taxes that we could not offset with our regular tax net operating loss carryforwards or our enhanced oil recovery credits. 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

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sale were primarily alternative minimum taxes as we were able to offset the related regular tax with our net operating loss carryforwards. As of December 31, 2004, we had utilized all of our federal tax net operating loss carryforwards, but had an estimated $27.8 million of enhanced oil recovery credits to carryforward. Since the ability to earn additional enhanced oil recovery credits is reduced or even eliminated based on the level of oil prices, our effective tax rate and cash taxes could both increase in the future if oil prices remain at current levels or increase further.

Our overall current income tax credit for 2002 was the result of a tax law change that allowed us to offset 100% of our 2001 alternative minimum taxes with our alternative minimum tax net operating loss carryforwards. Prior to the law change, we were able to offset only 90% of our alternative minimum taxes with these carryforwards. This change resulted in a refund of cash taxes paid for 2001 and a reclassification of tax expense between current and deferred taxes, but did not impact our overall effective tax rate.

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	2004	2003	2002
Oil and natural gas revenues	$36.88	$30.43	$ 21.17
Gain (loss) on settlements of derivative contracts	(7.01)	(4.91)	0.07
Lease operating expenses	(7.22)	(7.06)	(5.48)
Production taxes and marketing expenses	(1.55)	(1.17)	(0.92)
Production netback	21.10	17.29	14.84
CO_2 operating margin relating to industrial sales	0.41	0.51	0.48
General and administrative expenses	(1.78)	(1.20)	(0.96)
Net cash interest expense	(1.34)	(1.61)	(1.73)
Current income taxes and other	(1.78)	(0.01)	0.04
Changes in assets and liabilities relating to operations	(2.63)	0.62	(0.38)
Cash flow from operations	13.98	15.60	12.29
DD&A	(8.09)	(7.48)	(7.26)
Deferred income taxes	(1.37)	(2.08)	(1.84)
Non-cash hedging adjustments	(0.11)	0.28	0.24
Changes in assets and liabilities, loss on early retirement of debt, change in accounting principle and other non-cash items	2.43	(1.86)	0.17
Net income	$ 6.84	$ 4.46	$ 3.60

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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 no bank debt outstanding as of December 31, 2004. 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.

	EXPECTED MATURITY DATES					CARRYING	FAIR
AMOUNTS IN THOUSANDS	2005	2006	2007	2008	2009	VALUE	VALUE
Fixed rate debt:							
Subordinated debt, net of discount (The interest rate on the subordinated debt is a fixed rate of 7.5%.)	—	—	—	—	—	$223,397	$243,000

We enter into various financial contracts to 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 historically consisted of price floors, collars and fixed price swaps. Historically, we have generally attempted to hedge between 50% and 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, although our hedging percentage may vary relative to our debt levels. For 2005 and beyond, we have hedged significantly less, primarily because of our strong financial position resulted from our lower levels of debt relative to our cash flow from operations. 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. Much of our historical hedging activity has been done with collars, although for the COHO acquisition, we also used swaps in order to lock in the prices used in our economic forecasts. For 2005, all of our oil hedges are puts or price floors, allowing us to retain any price upside, while still providing protection in the event of lower prices at a fixed and determinable price (i.e. the cost of the put). We anticipate using more price floors in the future. 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 hedging position at year-end 2004, see Note 9 to the Consolidated Financial Statements.

Upon reaching a verbal agreement with the purchaser (Newfield Exploration Company) of our offshore properties, subject primarily to their further due diligence, we entered into natural gas swaps on a total of 23.6 Bcf for the period of July 2004 through December 2005, covering the anticipated natural gas production from our offshore properties for that period, with the tacit understanding with the prospective purchaser that these hedges would be transferred to them upon closing. These swaps did not qualify for hedge accounting and during the third quarter of 2004, we assigned them to Newfield. During the period that we owned them, we recognized approximately $2.5 million of gain as the hedges appreciated in value before we assigned them to Newfield. At about the same time, with the expectation that the offshore transaction would be

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

consummated, we retired, by purchasing offsetting contracts, 20 MMcf/d of our natural gas hedges for July to December of 2004, at a cost of approximately $3.9 million. This transaction, net of the related gain on the hedges assigned to Newfield, was the primary reason for the $1.3 million net charge to earnings during 2004 relating to our derivative contracts that were not part of the monthly cash settlements on our derivatives contracts.

At December 31, 2004, our derivative contracts were recorded at their fair value, which was a net liability of approximately $4.9 million, a decrease of approximately $39.7 million from the $44.6 million fair value liability recorded as of December 31, 2003. This change is the result of the expiration of most of our derivative contracts during 2004 due to the passage of time. Effective January 1, 2005, we have elected to de-designate our existing derivative contracts as hedges and to account for them as speculative contracts going forward. This means that any changes in the fair value of these derivative contracts will be charged to earnings on a quarterly basis instead of charging the effective portion to other comprehensive income and the balance to earnings. Information regarding our current hedging positions and historical hedging results is included in Note 9 to the Consolidated Financial Statements.

Based on NYMEX crude oil futures prices at December 31, 2004, prices were considerably higher than the floor price of $27.50, so we would not expect to receive any funds even if oil prices were to drop 10%. Since the oil hedges are puts or price floors, we do not have to make any payments on the hedges regardless of how high oil prices would go. Based on NYMEX natural gas futures prices at December 31, 2004, we would expect to make future cash payments of $4.2 million on our natural gas commodity hedges. If natural gas futures prices were to decline by 10%, the amount we would expect to pay under our natural gas commodity hedges would decrease to $0.8 million, and if futures prices were to increase by 10% we would expect to pay $7.6 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 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 ten percent 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 an oil and gas entity applies.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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 3% of the previous year's estimates and have been both positive and negative.

Changes in commodity prices also affect our reserve quantities. For instance, between 2001 and 2002, commodity prices rebounded from the prior year's fall, resulting in an increase to our reserve quantities of approximately 3.5 MMBOE. During 2003 and 2004, the change related to commodity prices was virtually zero, less than in prior years, as prices were relatively high at year-end 2002, 2003 and 2004. 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 DD&A rate from $7.98 per Bbl to approximately $7.64 per Bbl and a 5% decrease in our proved reserve quantities would have increased our DD&A rate to approximately $8.35 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 three 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 during the last two years are significantly less than the year-end prices used in our reserve report. This also can have the

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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 at year-end 2003 and year-end 2004. (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.

ASSET RETIREMENT OBLIGATIONS

We have significant obligations related to the plugging and abandonment of our oil and gas wells, and 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.

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 2004, net operating loss carryforwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we file our income tax returns. Further, we must assess the likelihood that we will be able to recover or utilize our deferred tax assets (primarily our enhanced oil recovery credits). 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, 2004, 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% change in our effective tax rate would have increased our calculated income tax expense by approximately $1,200,000, $800,000, and $700,000 for the years ended December 31, 2004, 2003 and 2002. See Note 7 to the Consolidated Financial Statements for further information concerning our income taxes.

HEDGING ACTIVITIES

We enter into derivative contracts (i.e., hedges) 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. With the adoption of SFAS No. 133 in 2001, every derivative instrument was 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 other comprehensive income (equity) to the extent that the hedge is effective and in the income statement to the extent it is ineffective. We recognized ineffectiveness on our hedges of $600,000 for 2002, $282,000 for 2003 and $2.7 million for 2004.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

With the significant changes in commodity prices over the last two years, the fair value of our hedges has fluctuated significantly. While most of this change in value is recorded in other comprehensive income as most of our historical hedges have qualified for hedge accounting, the dramatic swing in commodity prices and the corresponding effect on the fair value of our hedges can cause a dramatic change to our balance sheet. In order to qualify for hedge accounting the relationship between the hedging instruments and the hedged items must be highly effective in achieving the offset of changes in fair values or cash flows attributable to the hedged risk, both at the inception of the hedge and on an ongoing basis. We measure and compute hedge effectiveness on a quarterly basis. If a hedging instrument becomes ineffective, hedge accounting is discontinued and any deferred gains or losses on the cash flow hedge remain in accumulated other comprehensive income until the periods during which the hedges would have otherwise expired. If we determine it probable that a hedged forecasted transaction will not occur, deferred gains or losses on the hedging instrument are recognized in earnings immediately.

Most our current derivative hedging instruments qualify for hedge accounting although we plan to abandon hedge accounting as of January 1, 2005. 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. For our three most recently completed fiscal years, if we had not chosen to designate hedge accounting treatment to our oil and natural gas hedge contracts, or if none of our derivative contracts had qualified for hedge accounting treatment, we estimate that our net income would have increased or (decreased) for 2004, 2003 and 2002 by the following amounts: $25.0 million, $(7.8) million and $(38.5) million.

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

On December 16, 2004, the Financial Accounting Standards Board ("FASB") issued SFAS No. 123(R), which is a revision of SFAS No. 123. SFAS No. 123(R) supersedes APB 25 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) will require all share-based payments to employees, including grants of employee stock options, to be recognized in our Consolidated Statements of Operations based on their estimated fair values. Pro forma disclosure is no longer an alternative.

SFAS No. 123(R) must be adopted no later that July 1, 2005 and permits public companies to adopt its requirements using one of two methods:

- A "modified prospective" method in which compensation cost is recognized based on the requirements of SFAS No. 123(R) for all share-based payments granted prior to the effective date of SFAS No. 123(R) that remain unvested on the adoption date.
- A "modified retrospective" method which includes the requirements of the modified prospective method described above, but also permits entities to restate either all prior periods presented or prior interim periods of the year of adoption based on the amounts previously recognized under SFAS No. 123 for purposes of pro forma disclosures.

As permitted by SFAS No. 123, we currently account for share-based payments to employees using the intrinsic value method prescribed by APB 25 and related interpretations. As such, we generally do not recognize compensation expense associated with employee stock options. Accordingly, the adoption of SFAS No. 123(R)'s fair value method could have a significant impact on Denbury's future results of operations, although it will have no impact on our overall financial position. Had the Company adopted SFAS No 123(R) in prior periods, the impact would have approximated the impact of SFAS No. 123 as described in the pro forma net income and earnings per share disclosures in Note 1 to the Consolidated Financial Statements. The adoption of SFAS No. 123(R) will have no effect on the Company's unvested outstanding restricted stock awards. We currently plan to adopt the provisions of SFAS No. 123(R) on July 1, 2005 using the modified prospective method. Although we have not completed evaluating the impact the adoption of SFAS No. 123(R) will have on our future results of operations, we currently estimate the impact on an annual basis will be similar to our pro forma disclosures for SFAS No. 123 in Note 1 to the Consolidated Financial Statements.

SFAS No. 123(R) also requires the tax benefits in excess of recognized compensation expenses to be reported as a financing cash flow, rather than as an operating cash flow as required under current literature. This requirement may serve to reduce Denbury's future cash provided by operating activities and increase future cash provided by financing activities, to the extent of associated tax benefits that may be realized in the future. While we cannot estimate what those amounts will be in the future (because they depend, among other things, when employees exercise stock options), the amount of operating cash flows recognized in prior periods for such excess tax deductions were $4.8 million, $1.3 million and $0.7 million during the years ended December 31, 2004, 2003, and 2002, respectively.

In July 2004, the Emerging Issues Task Force of the FASB issued EITF 04-05, "Investor's Accounting for an Investment in a Limited Partnership When the Investor is the Sole General Partner and the Limited Partners Have Certain Rights." In question is what rights held by the limited partners preclude consolidation of the limited partnership by the sole general partner. The Task Force noted that in practice differing views have evolved concerning this issue and it has asked the FASB staff to develop this issue for discussion at a future date. Denbury is the general partner of Genesis Energy, L.P. ("Genesis") and currently does not consolidate Genesis in its financial results based primarily on certain rights of the limited partner. This EITF has been issued for comment, with the comment period ending in February 2005. Based on our initial review of the proposed EITF, we currently do not believe that it will impact our consolidation treatment of Genesis; however, this determination is subject to further review and evaluation of the final rules. See Note 3, "Related Party Transactions – Genesis" for further information regarding Denbury's accounting for its investment in Genesis.

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, hydrocarbon reserves, hydrocarbon prices, liquidity, regulatory matters, mark-to-market values, competition and long-term forecasts of production, finding cost, rates of return, estimated 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,

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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 43 through 44.

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, 2004. 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, 2004, based on those criteria.

Our management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their audit report which appears herein.

REPORTS OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRMS

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

We have completed an integrated audit of Denbury Resources Inc.'s 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audit, 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 ("the Company") at December 31, 2004, and the results of their operations and their cash flows for the year ended December 31, 2004 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 audit. We conducted our audit 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 audit provides a reasonable basis for our opinion.

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, 2004 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, 2004, 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. (CONTINUED ON PAGE 53)

REPORTS OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRMS

(continued from page 52)

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

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

PricewaterhouseCoopers LLP

PRICEWATERHOUSECOOPERS LLP
Dallas, Texas
March 14, 2005

To the Stockholders of Denbury Resources Inc.

We have audited the accompanying consolidated balance sheet of Denbury Resources Inc. and Subsidiaries (the "Company") as of December 31, 2003, and the related consolidated statements of operations, cash flows, stockholders' equity and comprehensive income for each of the two years in the period ended December 31, 2003. 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 in accordance with 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 includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2003, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the financial statements under the caption "Asset Retirement Obligations," the Company changed its method of accounting for asset retirement obligations in 2003 as required by Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations."

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Dallas, Texas
March 8, 2004

CONSOLIDATED BALANCE SHEETS

(IN THOUSANDS, EXCEPT SHARES)	DECEMBER 31, 2004	DECEMBER 31, 2003
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 33,039	$ 24,188
Short-term investments	57,171	—
Accrued production receivable	44,790	33,944
Related party receivable – Genesis	745	6,927
Trade and other receivables, net of allowance of $236 and $238	10,963	18,080
Deferred tax asset	25,189	25,016
Derivative assets	949	—
Total current assets	172,846	108,155
PROPERTY AND EQUIPMENT		
Oil and natural gas properties (using full cost accounting)		
Proved	1,326,401	1,409,579
Unevaluated	20,253	46,065
CO_2 properties and equipment	132,685	85,467
Other	25,929	16,450
Less accumulated depletion and depreciation	(707,906)	(705,050)
Net property and equipment	797,362	852,511
Investment in Genesis	6,791	7,450
Other assets	15,707	14,505
TOTAL ASSETS	$ 992,706	$ 982,621

<continued on page 55 >

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS (CONTINUED)

(IN THOUSANDS, EXCEPT SHARES)	DECEMBER 31, 2004	DECEMBER 31, 2003
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 51,860	$ 62,349
Oil and gas production payable	24,856	22,215
Derivative liabilities	5,815	42,010
Short-term capital lease obligations – Genesis	375	–
Total current liabilities	82,906	126,574
LONG-TERM LIABILITIES		
Capital lease obligations – Genesis	4,184	–
Long-term debt	223,397	298,203
Asset retirement obligations	18,944	41,711
Derivative liabilities	–	2,603
Deferred revenue – Genesis	23,378	21,468
Deferred tax liability	97,125	68,555
Other	1,100	2,305
Total long-term liabilities	368,128	434,845
COMMITMENTS AND CONTINGENCIES (NOTE 10)		
STOCKHOLDERS' EQUITY		
Preferred stock, $.001 par value, 25,000,000 shares authorized; none issued and outstanding	–	–
Common stock, $.001 par value, 100,000,000 shares authorized; 56,607,877, and 54,190,042 shares issued at December 31, 2004 and 2003, respectively	57	54
Paid-in capital in excess of par	441,023	401,709
Deferred compensation	(21,678)	–
Retained earnings	129,104	46,656
Accumulated other comprehensive loss	(4,788)	(27,113)
Treasury stock, at cost, 93,072 and 8,162 shares at December 31, 2004 and 2003, respectively	(2,046)	(104)
Total stockholders' equity	541,672	421,202
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 992,706	$ 982,621

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF OPERATIONS

(IN THOUSANDS, EXCEPT PER SHARE DATA)	YEAR ENDED DECEMBER 31, 2004	2003	2002
REVENUES			
Oil, natural gas and related product sales			
Unrelated parties	$ 381,253	$ 336,521	$ 251,972
Related party – Genesis	63,524	48,942	22,922
CO_2 sales and transportation fees			
Unrelated parties	1,183	7,512	7,580
Related party – Genesis	5,093	676	—
Gain (loss) on effective hedge contracts	(70,469)	(62,210)	932
Interest income and other	2,388	1,573	1,746
Total revenues	382,972	333,014	285,152
EXPENSES			
Lease operating expenses	87,107	89,439	71,188
Production taxes and marketing expenses	17,569	14,819	11,902
Transportation expense – Genesis	1,168	—	—
CO_2 operating expenses	1,338	1,710	1,400
General and administrative	21,461	15,189	12,426
Interest	19,468	23,201	26,833
Loss on early retirement of debt	—	17,629	—
Depletion, depreciation and accretion	97,527	94,708	94,236
(Gain) loss on ineffective hedge contracts	15,358	(3,578)	(3,093)
Total expenses	260,996	253,117	214,892
Equity in net income (loss) of Genesis	(136)	256	55
Income before income taxes	121,840	80,153	70,315
Income tax provision (benefit)			
Current income taxes	22,929	(91)	(406)
Deferred income taxes	16,463	26,303	23,926
Income before cumulative effect of change in accounting principle	82,448	53,941	46,795
Cumulative effect of change in accounting principle, net of income taxes of $1,600	—	2,612	—
NET INCOME	$ 82,448	$ 56,553	$ 46,795
NET INCOME PER SHARE – BASIC			
Income before cumulative effect of change in accounting principle	$ 1.50	$ 1.00	$ 0.88
Cumulative effect of change in accounting principle	—	0.05	—
Net income per common share – basic	$ 1.50	$ 1.05	$ 0.88
NET INCOME PER SHARE – DILUTED			
Income before cumulative effect of change in accounting principle	$ 1.44	$ 0.97	$ 0.86
Cumulative effect of change in accounting principle	—	0.05	—
Net income per common share – diluted	$ 1.44	$ 1.02	$ 0.86
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING			
Basic	54,871	53,881	53,243
Diluted	57,301	55,464	54,365

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	YEAR ENDED DECEMBER 31,		
(IN THOUSANDS)	2004	2003	2002
CASH FLOW FROM OPERATING ACTIVITIES:			
Net income	$ 82,448	$ 56,553	$ 46,795
Adjustments needed to reconcile to net cash flow provided by operations:			
Depreciation, depletion and accretion	97,527	94,708	94,236
Deferred income taxes	16,463	26,303	23,926
Deferred revenue – Genesis	(2,399)	(322)	—
Deferred compensation – restricted stock	1,601	—	—
Loss on early retirement of debt	—	17,629	—
Non-cash hedging adjustments	1,270	(3,578)	(3,093)
Amortization of debt issue costs and other	3,283	1,121	2,701
Cumulative effect of change in accounting principle	—	(2,612)	—
Changes in assets and liabilities relating to operations:			
Accrued production receivable	(19,776)	(3,079)	(14,381)
Trade and other receivables	7,475	(1,234)	15,078
Derivative assets and liabilities	(7,519)	—	8,427
Other assets	(166)	7	133
Accounts payable and accrued liabilities	(10,522)	8,862	(17,217)
Oil and gas production payable	2,641	4,906	3,869
Other liabilities	(3,674)	(1,649)	(874)
NET CASH PROVIDED BY OPERATING ACTIVITIES	168,652	197,615	159,600
CASH FLOW USED FOR INVESTING ACTIVITIES:			
Oil and natural gas expenditures	(167,001)	(146,596)	(99,273)
Acquisitions of oil and gas properties	(11,069)	(11,848)	(56,364)
Investment in Genesis	—	(5,026)	(2,170)
Acquisition of CO_2 assets and capital expenditures	(50,265)	(22,673)	(16,445)
Net purchases of other assets	(5,210)	(2,192)	(3,688)
Deposit on oil and gas property acquisitions	(4,507)	—	—
Increase in restricted cash	(542)	(848)	(909)
Purchases of short-term investments	(76,517)	—	—
Sales of short-term investments	19,350	—	—
Net proceeds from CO_2 production payment – Genesis	4,636	23,895	—
Proceeds from sales of oil and gas properties	10,042	29,410	7,688
Sale of Denbury Offshore, Inc.	187,533	—	—
NET CASH USED FOR INVESTING ACTIVITIES	(93,550)	(135,878)	(171,161)
CASH FLOW FROM FINANCING ACTIVITIES:			
Bank repayments	(88,000)	(160,000)	(40,000)
Bank borrowings	13,000	85,000	49,130
Payments on capital lease obligations – Genesis	(32)	—	—
Repayment of subordinated debt obligations, including redemption premium	—	(209,000)	—
Issuance of subordinated debt, net of discount	—	223,054	—
Issuance of common stock	13,168	5,537	3,594
Purchase of treasury stock	(3,977)	(1,268)	—
Costs of debt financing	(410)	(4,812)	(719)
NET CASH PROVIDED BY (USED FOR) FINANCING ACTIVITIES	(66,251)	(61,489)	12,005
NET INCREASE IN CASH AND CASH EQUIVALENTS	8,851	248	444
Cash and cash equivalents at beginning of year	24,188	23,940	23,496
Cash and cash equivalents at end of year	$ 33,039	$ 24,188	$ 23,940

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

(DOLLAR AMOUNTS IN THOUSANDS)	COMMON STOCK ($.001 PAR VALUE) SHARES	COMMON STOCK AMOUNT	PAID-IN CAPITAL IN EXCESS OF PAR	RESTRICTED STOCK DEFERRED COMPENSATION	RETAINED EARNINGS (ACCUMULATED DEFICIT)	ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	TREASURY STOCK (AT COST) SHARES	TREASURY STOCK AMOUNT	TOTAL STOCKHOLDERS' EQUITY
BALANCE – DECEMBER 31, 2001	52,956,825	$ 53	$ 391,557	$ –	$(56,670)	$ 14,228	–	$ –	$349,168
Issued pursuant to employee stock purchase plan	203,893	–	1,928	–	–	–	–	–	1,928
Issued pursuant to employee stock option plan	370,120	1	1,665	–	–	–	–	–	1,666
Issued pursuant to directors' compensation plan	8,491	–	82	–	–	–	–	–	82
Tax benefit from stock options	–	–	674	–	–	–	–	–	674
Derivative contracts, net	–	–	–	–	–	(33,516)	–	–	(33,516)
Net income	–	–	–	–	46,795	–	–	–	46,795
BALANCE – DECEMBER 31, 2002	53,539,329	54	395,906	–	(9,875)	(19,288)	–	–	366,797
Repurchase of common stock	–	–	–	–	–	–	100,000	(1,276)	(1,276)
Issued pursuant to employee stock purchase plan	94,968	–	1,174	–	(22)	–	(91,838)	1,172	2,324
Issued pursuant to employee stock option plan	550,090	–	3,213	–	–	–	–	–	3,213
Issued pursuant to directors' compensation plan	5,655	–	69	–	–	–	–	–	69
Tax benefit from stock options	–	–	1,347	–	–	–	–	–	1,347
Derivative contracts, net	–	–	–	–	–	(7,825)	–	–	(7,825)
Net income	–	–	–	–	56,553	–	–	–	56,553
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	23,278	(23,279)	–	–	–	–	–
Amortization of deferred compensation	–	–	–	1,601	–	–	–	–	1,601
Tax benefit from stock options	–	–	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	$441,023	$(21,678)	$129,104	$ (4,788)	93,072	$(2,046)	$541,672

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	YEAR ENDED DECEMBER 31,		
(IN THOUSANDS)	2004	2003	2002
NET INCOME	$ 82,448	$ 56,553	$ 46,795
Other comprehensive income (loss), net of tax:			
Change in fair value of derivative contracts, net of tax of ($19,328), ($26,969) and ($18,784), respectively	(31,535)	(44,002)	(30,648)
Reclassification adjustments related to settlements of derivative contracts, net of tax of $33,025, $22,173 and ($1,758), respectively	53,884	36,177	(2,868)
Unrealized loss on securities available for sale, net of tax of ($15)	(24)	—	—
COMPREHENSIVE INCOME	$104,773	$ 48,728	$ 13,279

See Notes to Consolidated Financial Statements.

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. Denbury has 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 third parties for various industrial uses.

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 general partnership agreement we do not consolidate Genesis. See Note 3 for more information regarding our related party transactions with Genesis and summary financial information. 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.

Effective December 29, 2003, Denbury Resources Inc. changed its corporate structure to a holding company format. The purposes of creating the holding company structure were to better reflect the operating practices and methods of Denbury, to improve its economics, and to provide greater administrative and operational flexibility. 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). The reorganization was structured as a tax free reorganization to Denbury's stockholders and all outstanding capital stock of the original public company was automatically converted into the identical number of and type of shares of the new public holding company. Stockholders' ownership interests in the business did not change as a result of the new structure and shares of the Company remained publicly traded under the same symbol (DNR) on the New York Stock Exchange. The new parent holding company is co-obligor (or guarantor, as appropriate) regarding the payment of principal and interest on Denbury's outstanding debt securities.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

C) Asset Retirement Obligations. On January 1, 2003, we adopted the provisions of Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations." In general, our future asset retirement obligations relate to future costs associated with plugging and abandonment of our oil and natural gas wells, removal of equipment and facilities from leased acreage and returning such land to its original condition. SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be 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. Prior to the adoption of this new standard, we recognized a provision for our asset retirement obligations each period as part of our depletion and depreciation calculation, based on the unit-of-production method. See Note 4 for more information regarding our change in accounting related to the adoption of SFAS No. 143.

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 13 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, are depreciated principally on a straight-line basis over estimated useful lives. Estimated useful lives are generally as follows: furniture and fixtures and vehicles 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 receivables.

We follow the "sales method" of accounting for our oil and natural gas revenue, whereby we recognize sales 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, 2004 and 2003, 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. In accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, derivative financial instruments are recorded on the balance sheet as either an asset or a liability measured at 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 hedge accounting, the change in fair value of the derivative is recognized either currently in earnings or deferred in other comprehensive income (equity) depending on the type of hedge and to what extent the hedge is effective. All of our current derivative instruments that qualify for hedge accounting are cash flow hedges.

In order to qualify for hedge accounting the relationship between the hedging instruments and the hedged items must be highly effective in achieving the offset of changes in fair values or cash flows attributable to the hedged risk, both at the inception of the hedge and on an ongoing basis. We measure hedge effectiveness on a quarterly basis. Hedge accounting is discontinued prospectively when a hedging instrument becomes ineffective. We assess hedge effectiveness based on total changes in the fair value of options used in cash flow hedges rather than changes of intrinsic value only. As a result, changes in the entire fair value of option contracts are deferred in accumulated other comprehensive income, to the extent they are effective, until the hedged transaction is completed. If a hedge becomes ineffective, any deferred gains or losses on the cash flow hedge remain in accumulated other comprehensive income until the underlying production related to the derivative hedge has been delivered. If it is determined probable that a hedged forecasted transaction will not occur, and the hedge is not re-designated, deferred gains or losses on the hedging instrument are recognized in earnings immediately.

Receipts and payments resulting from settlements of derivative hedging instruments qualifying for hedge accounting are recorded in "Gain (loss) on effective hedge contracts" included in revenues in the Consolidated Statements of Operations. We apply Derivative Implementation Group Issue G20 in accounting for our net purchased puts and collars, which allows the amortization of the cost of net purchased options over the period of the hedge. We record this amortization and any gains or losses resulting from hedge ineffectiveness in "Gain (loss) on ineffective hedge contracts" under expenses in the Consolidated Statements of Operations. Denbury's hedging activities are further discussed in Note 9.

Effective January 1, 2005, we have decided to de-designate from hedge accounting treatment our existing derivative hedging instruments. As such, we will account for our derivative instruments in future periods as speculative contracts and future changes in the fair value of these instruments will be recognized in the income statement in the period of change. While this change may result in more volatility in our income in future periods, we believe that the benefits associated with applying hedge accounting do not outweigh the cost, time and effort required to apply hedge accounting.

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, short-term investments, trade and accrued production receivables and the derivative hedging instruments discussed above. Our cash equivalents and short-term investments 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,

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

SHORT-TERM INVESTMENTS

Our short-term investments consist primarily of investment grade debt securities that are classified as "available-for-sale" in accordance with the provisions of SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." Available-for-sale securities are stated at fair value, based on quoted market prices, with the unrealized gain or loss, net of tax, reported in other comprehensive income. Premiums and discounts are amortized or accreted into earnings over the life of the related security. Dividend and interest income is recognized when earned. We have no investments that are considered to be trading securities.

The following is a summary of current available-for-sale marketable securities at December 31, 2004:

	DECEMBER 31, 2004			
(IN THOUSANDS)	AMORTIZED COST	GROSS UNREALIZED GAINS	GROSS UNREALIZED LOSSES	ESTIMATED FAIR VALUE
Certificate of deposits	$ 2,000	$ —	$ —	$2,000
Government and agency obligations	17,470	—	(14)	17,456
Other debt securities	37,739	4	(28)	37,715
Total current available-for-sale securities	$57,209	$ 4	$(42)	$57,171

RESTRICTED CASH AND INVESTMENTS

At December 31, 2004 and 2003, we had approximately $6.4 million and $9.5 million, respectively, of restricted cash and investments held in escrow accounts for future site reclamation costs. These balances are recorded at amortized cost and are included in "Other Assets" in the Consolidated Balance Sheets. The estimated fair market value of these investments at December 31, 2004 and 2003 was 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, restricted stock and any other outstanding convertible securities.

For each of the three years in the period ended December 31, 2004, there were no adjustments to net income for purposes of calculating basic and diluted net income per common share. The following is a reconciliation of the weighted average shares used in the basic and diluted net income per common share computations:

(IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2004	2003	2002
Weighted average common shares – basic	54,871	53,881	53,243
Potentially dilutive securities:			
Stock options	2,413	1,583	1,122
Restricted stock	17	—	—
Weighted average common shares – diluted	57,301	55,464	54,365

The weighted average common shares – basic amount in 2004 excludes 1,150,000 shares of non-vested restricted stock granted in 2004 that is subject to future time vesting requirements. As these restricted shares vest, they will be included in the shares outstanding used to calculate basic net income per common share. 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 restricted shares were issued in August through December 2004 and have been included in the calculation for the periods they were outstanding. These shares may result in greater dilution in future periods, depending on the market price of our common stock during those periods. We excluded stock options representing 40,000 shares in 2004, 1.0 million shares in 2003 and 1.7 million shares in 2002 from our diluted shares outstanding because their inclusion would be antidilutive, as their exercise prices exceeded the average market price of our common stock during the respective periods.

STOCK-BASED COMPENSATION

We issue stock options to all of our employees under our stock option plans, which are described more fully in Note 8. We account for our stock options 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 stock-based employee compensation expense is reflected in net income as long as the stock options have an exercise price equal to the underlying common stock on the date of grant. The following table illustrates the effect on net income and net income per common share if we had applied the fair value provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," as amended by SFAS No. 148, in accounting for our stock options.

(IN THOUSANDS, EXCEPT PER SHARE DATA)	YEAR ENDED DECEMBER 31, 2004	2003	2002
NET INCOME:			
Net income, as reported	$82,448	$56,553	$46,795
Add: Stock-based compensation included in reported net income, net of related tax effects	977	—	—
Less: Stock-based compensation expense applying fair value based method, net of related tax effects	3,772	3,101	2,853
Pro forma net income	$79,653	$53,452	$43,942
NET INCOME PER COMMON SHARE			
As reported:			
Basic	$ 1.50	$ 1.05	$ 0.88
Diluted	1.44	1.02	0.86
Pro forma:			
Basic	$ 1.45	$ 0.99	$ 0.83
Diluted	1.40	0.98	0.83

The weighted average fair value of options granted using the Black-Scholes option-pricing model and the weighted average assumptions used in determining those fair values are as follows:

	2004	2003	2002
Weighted average fair value of options granted	$6.44	$6.02	$4.17
Risk free interest rate	3.34%	2.94%	4.05%
Expected life	5 years	5 years	5 years
Expected volatility	46.8%	59.6%	61.4%
Dividend yield	—	—	—

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 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

On December 16, 2004, the Financial Accounting Standards Board ("FASB") issued SFAS No. 123(R), which is a revision of SFAS No. 123. SFAS No. 123(R) supersedes APB 25 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) will require all share-based payments to employees, including grants of employee stock options, to be recognized in our Consolidated Statements of Operations based on their estimated fair values. Pro forma disclosure is no longer an alternative.

SFAS No. 123(R) must be adopted no later than July 1, 2005 and permits public companies to adopt its requirements using one of two methods:

- A "modified prospective" method in which compensation cost is recognized based on the requirements of SFAS No. 123(R) for all share-based payments granted prior to the effective date of SFAS No. 123(R) that remain unvested on the adoption date.
- A "modified retrospective" method which includes the requirements of the modified prospective method described above, but also permits entities to restate either all prior periods presented or prior interim periods of the year of adoption based on the amounts previously recognized under SFAS No. 123 for purposes of pro forma disclosures.

As permitted by SFAS No. 123, we currently account for share-based payments to employees using the intrinsic value method prescribed by APB 25 and related interpretations. As such, we generally do not recognize compensation expense associated with employee stock options. Accordingly, the adoption of SFAS No. 123(R)'s fair value method could have a significant impact on Denbury's future results of operations, although it will have no

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

impact on our overall financial position. Had the Company adopted SFAS No. 123(R) in prior periods, the impact would have approximated the impact of SFAS No. 123 as described in the pro forma net income and earnings per share disclosures above. The adoption of SFAS No. 123(R) will have no effect on the Company's unvested outstanding restricted stock awards. We currently plan to adopt the provisions of SFAS No. 123(R) on July 1, 2005 using the modified prospective method. Although we have not completed evaluating the impact the adoption of SFAS No. 123(R) will have on our future results of operations, we currently estimate the impact on an annual basis will be similar to our pro forma disclosures for SFAS No. 123 above.

SFAS No. 123(R) also requires the tax benefits in excess of recognized compensation expenses to be reported as a financing cash flow, rather than as an operating cash flow as required under current literature. This requirement may serve to reduce Denbury's future cash provided by operating activities and increase future cash provided by financing activities, to the extent of associated tax benefits that may be realized in the future. While we cannot estimate what those amounts will be in the future (because they depend, among other things, when employees exercise stock options), the amount of operating cash flows recognized in prior periods for such excess tax deductions were $4.8 million, $1.3 million and $0.7 million during the years ended December 31, 2004, 2003, and 2002, respectively.

In September 2004, the SEC issued Staff Accounting Bulletin No. 106 (SAB 106), which clarifies the calculation of the full cost ceiling and depreciation, depletion, and amortization ("DD&A") of oil and gas properties in conjunction with accounting for asset retirement obligations under SFAS No. 143. The guidance in SAB 106 had no impact on our consolidated financial statements.

Note 2. Acquisitions and Divestitures

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 which we received between April 1st 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).

COHO GULF COAST PROPERTIES

In August 2002, we acquired the Gulf Coast properties of COHO Energy, Inc., auctioned in the U.S. Bankruptcy Court in Dallas, Texas. Our net purchase price was $48.2 million and included nine fields, eight of which are located in Mississippi and one in Texas. At December 31, 2002, these properties had reserves of approximately 15.1 million barrels of oil and net production of approximately 4,000 barrels of oil per day. The Mississippi fields included interests in the Brookhaven, Laurel, Martinville, Soso and Summerland Fields, with such interests representing operational control with working interests in excess of 90%, plus interests in the smaller Bentonia, Cranfield and Glazier Fields.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In February 2003, we sold Laurel Field, acquired in the COHO acquisition, for $25.9 million and other consideration which included an interest in Atchafalaya Bay Field (where we already owned an interest) and seismic over that area. At December 31, 2002, Laurel Field had approximately 7.4 MMBbls of proved reserves. In March 2003, we sold the Bentonia and Glazier fields for approximately $1.6 million. The proceeds from the sale of Laurel Field were used to reduce our bank debt.

Note 3. Related Party Transactions – Genesis

On May 14, 2002, a newly formed subsidiary of Denbury acquired Genesis Energy, L.L.C. (which was subsequently converted to Genesis Energy, Inc.), the general partner of Genesis, a publicly traded master limited partnership, for total consideration, including expenses and commissions, of approximately $2.2 million. Genesis has two primary lines of business: crude oil gathering and marketing and pipeline transportation, primarily in Mississippi, Texas, Alabama and Florida. In November 2003, through our subsidiary general partner, we purchased an additional 689,000 partnership common units and 14,000 general partner units of Genesis for $7.15 per unit, with an aggregate purchase price of approximately $5.0 million. With these additional units, our ownership interest increased to approximately 9.25% (2.0% general partner ownership and 7.25% limited partner ownership).

We are accounting 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 2004 was ($136,000), for 2003 was $256,000 and for 2002 was $55,000, representing 2% of Genesis' net income (loss) for the periods from May 14, 2002 through October 31, 2003 and 9.25% of Genesis' net income (loss) for the periods from November 1, 2003 through December 31, 2004. Genesis Energy, Inc., the general partner of which we own 100%, has guaranteed the bank debt of Genesis, which consisted of $15.3 million of debt and $22.8 million in letters of credit at December 31, 2004. 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 $7.2 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 $11.1 million at December 31, 2004, based on quoted market values.

Over the past several years, including the period prior to our investment in Genesis, we sold certain of our oil production to Genesis. Beginning in September 2004, we elected to sell our own crude oil to independent third parties rather than to Genesis. As such, we discontinued our direct sales to Genesis and began to transport our crude oil to our sales point using Genesis' common carrier pipeline. For these transportation services, we pay Genesis a fee for the use of their pipeline and trucking services. For 2004, we expensed $1.2 million for these transportation services. At December 31, 2004, we had a receivable from Genesis of $0.7 million and $6.9 million at December 31, 2003. We recorded oil sales to Genesis of $63.5 million, $48.9 million and $22.9 million for the years ended December 31, 2004, 2003, and 2002, respectively. Denbury received other miscellaneous payments from Genesis, including $120,000 in both 2004 and 2003 in director fees for certain executive officers of Denbury that are board members of Genesis, and $508,000 in 2004 and $57,000 in 2003 of pro rata dividend distributions from Genesis.

TRANSPORTATION LEASES

During 2004, we requested that Genesis build two pipelines for our benefit. The pipelines were to transport our crude oil from Olive and McComb Fields in Southwest Mississippi to Genesis' main crude oil pipeline to improve our ability to market our crude oil, and to transport CO_2 from our main CO_2 pipeline to Brookhaven Field for our tertiary operations. As part of these arrangements, we entered into two transportation agreements. The first agreement, entered into in November, was to transport crude oil from Olive Field. This agreement is for 10 years and has a minimum payment of approximately $18,000 per month. This minimum monthly charge will increase for any volumes transported in excess of a stated monthly volume. In December, we entered into the second transportation agreement to transport CO_2 to Brookhaven Field in Southwest Mississippi. This agreement is for an eight-year period and has minimum payments of approximately $49,000 per month. This minimum monthly payment will increase for any volumes transported in excess of a stated monthly volume. Genesis will operate and maintain these pipelines at its own expense.

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, 2004, we had $4.6 million recorded as debt, of which $375,000 was current.

CO_2 VOLUMETRIC PRODUCTION PAYMENT

In November 2003, we sold 167.5 Bcf of CO_2 to Genesis for $24.9 million ($23.9 million as adjusted for interim cash flows from the September 1, 2003 effective date and for transaction costs) under a volumetric production payment ("VPP"), and assigned to Genesis three of our existing long-term commercial CO_2 supply agreements with our industrial customers. These industrial contracts represented approximately 60% of our then current industrial CO_2 sales volumes. Pursuant to the VPP, Genesis may take up to 52.5 MMcf/d of CO_2 through 2009, 43.0 MMcf/d from 2010 through 2012, and 25.2 MMcf/d to the end of the term.

On August 26, 2004, we closed on another transaction with Genesis, selling to them a 33.0 Bcf volumetric production payment ("VPPII") of CO_2 for $4.8 million ($4.6 million as adjusted for interim cash flows from the July 1 effective date and for transaction costs) along with a related long-term supply agreement with an industrial customer. Pursuant to the VPPII, Genesis may take up to 9 MMcf/d of CO_2 to the end of the contract term.

We have recorded the net proceeds of these volumetric production payment sales as deferred revenue and will recognize such revenue as CO_2 is delivered during the term of the two volumetric production payments. At December 31, 2004 and 2003, $25.8 million and $23.6 million, respectively, was recorded as deferred revenue of which $2.4 million and $2.1 million was included in current liabilities at December 31, 2004 and 2003, respectively. During 2004 and 2003, we recognized deferred revenue of $2.4 million and $0.3 million, respectively, for deliveries under the VPP and VPPII. We provide Genesis with certain processing and transportation services in connection with these agreements for a fee of approximately $0.16 per Mcf of CO_2 delivered to their industrial customers, which resulted in $2.7 million and $0.4 million in revenue to Denbury for the years ended December 31, 2004 and 2003, respectively.

SUMMARIZED FINANCIAL INFORMATION OF GENESIS ENERGY, L.P.

	YEAR ENDED DECEMBER 31,	
(IN THOUSANDS)	2004	2003
Revenues	$ 927,143	$657,897
Cost of sales	908,804	644,157
Other expenses	19,288	14,159
Income (loss) from discontinued operations	(463)	13,741
Net income (loss)	$ (1,412)	$ 13,322

	DECEMBER 31,	
(IN THOUSANDS)	2004	2003
Current assets	$ 77,396	$ 88,211
Non-current assets	65,758	58,904
Total assets	$ 143,154	$ 147,115
Current liabilities	$ 81,938	$ 87,244
Non-current liabilities	15,460	7,000
Partners' capital	45,756	52,871
Total liabilities and partners' capital	$ 143,154	$ 147,115

NOTE 4. ASSET RETIREMENT OBLIGATIONS

On January 1, 2003, we adopted the provisions of SFAS No. 143, "Accounting for Asset Retirement Obligations." In general, our future asset retirement obligations relate to future costs associated with plugging and abandonment of our oil and natural gas wells, removal of equipment and facilities from leased acreage and returning such land to its original

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

condition. SFAS 143 requires that the fair value of a liability for an asset retirement obligation be 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. Prior to the adoption of this new standard, we recognized a provision for our asset retirement obligations each period as part of our depletion and depreciation calculation, based on the unit-of-production method.

The adoption of SFAS No. 143 on January 1, 2003, required us to record (i) a $41.0 million liability for our future asset retirement obligations (an increase of $34.1 million in our liability for asset retirement obligations that we had recorded at December 31, 2002), (ii) a $34.4 million increase in oil and natural gas properties, (iii) a $3.9 million decrease in accumulated depreciation and depletion, and (iv) a $2.6 million gain as a cumulative effect adjustment of a change in accounting principle, net of taxes.

The following pro forma data summarizes Denbury's net income and net income per common share as if we had applied the provisions of SFAS No. 143 in prior periods, and as if we had removed the first quarter 2003 cumulative effect adjustment for the adoption of SFAS No. 143:

	YEAR ENDED DECEMBER 31,	
(IN THOUSANDS, EXCEPT PER SHARE DATA)	2003	2002
Net income, as reported	$56,553	$46,795
Pro forma adjustments to reflect retroactive adoption of SFAS 143	(2,612)	473
Pro forma net income	$53,941	$47,268
Net income per common share:		
As reported:		
Basic	$ 1.05	$ 0.88
Diluted	1.02	0.86
Pro forma:		
Basic	$ 1.00	$ 0.89
Diluted	0.97	0.87

The following table summarizes the changes in our asset retirement obligations for the years ended December 31, 2004 and 2003.

	YEAR ENDED DECEMBER 31,	
(IN THOUSANDS)	2004	2003
Beginning asset retirement obligation	$ 43,812	$ 6,845
Cumulative effect adjustment for SFAS No. 143, January 1, 2003	—	34,110
Liabilities incurred during period	3,206	3,405
Liabilities settled during period	(2,549)	(1,007)
Liabilities sold during period	(25,337)	(2,393)
Accretion expense	2,408	2,852
Ending asset retirement obligation	$ 21,540	$43,812

Liabilities sold during the period primarily represent the asset retirement obligations previously associated with our offshore assets held by Denbury Offshore, Inc., which we sold in July 2004. At December 31, 2004 and 2003, $2.6 million and $2.1 million of our asset retirement obligation was classified in "Accounts payable and accrued liabilities" under current liabilities in our Consolidated Balance Sheets. We have escrow accounts that are legally restricted for certain of our asset retirement obligations. The balances of these escrow accounts were $6.4 million at December 31, 2004, and $9.5 million at December 31, 2003, and are included in "Other assets" in our Consolidated Balance Sheets.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 5. Property and Equipment

(IN THOUSANDS)	DECEMBER 31, 2004	2003
Oil and natural gas properties:		
Proved properties	$1,326,401	$1,409,579
Unevaluated properties	20,253	46,065
Total	1,346,654	1,455,644
Accumulated depletion and depreciation	(686,799)	(690,395)
Net oil and natural gas properties	659,855	765,249
CO_2 properties	132,685	85,467
Accumulated depletion and depreciation	(10,636)	(5,971)
Net CO_2 properties	122,049	79,496
Other	25,929	16,450
Accumulated depletion and depreciation	(10,471)	(8,684)
Net other	15,458	7,766
Net property, equipment and other	$ 797,362	$ 852,511

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, 2004 and 2003 and the year in which they were incurred follows:

	DECEMBER 31, 2004					DECEMBER 31, 2003			
	COSTS INCURRED DURING:					COSTS INCURRED DURING:			
(IN THOUSANDS)	2004	2003	2002	2001	TOTAL	2003	2002	2001	TOTAL
Property acquisition costs	$3,400	$ 2,519	$1,207	$1,798	$ 8,924	$ 3,640	$ 6,301	$ 21,169	$ 31,110
Exploration costs	3,787	2,771	3,550	1,221	11,329	6,528	5,291	3,136	14,955
Total	$ 7,187	$5,290	$4,757	$3,019	$20,253	$10,168	$11,592	$24,305	$46,065

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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 6. NOTES PAYABLE AND LONG-TERM INDEBTEDNESS

(IN THOUSANDS)	DECEMBER 31, 2004	2003
7.5% Senior Subordinated Notes due 2013	$225,000	$225,000
Discount on Senior Subordinated Notes	(1,603)	(1,797)
Capital lease obligations – Genesis	4,559	—
Senior bank loan	—	75,000
Total	227,956	298,203
Less current obligations	375	—
Long-term debt and capital lease obligations	$ 227,581	$298,203

SENIOR BANK LOAN

On September 1, 2004, we entered into a new bank credit agreement which modified the prior agreement by (i) creating a structure wherein the commitment amount and borrowing base amount are no longer the same, (ii) improving our credit pricing by reducing the interest rate chargeable at certain levels of borrowing, (iii) extending the term by three years to April 30, 2009, (iv) reducing the collateral requirements, (v) authorizing up to $20 million of possible future CO_2 volumetric production payment transactions with Genesis Energy, and (vi) other minor modifications and corrections. Under the new agreement, our borrowing base is currently set at $200 million, with an initial commitment amount of $100 million. The borrowing base represents the amount we can borrow from a credit standpoint based on our assets, as confirmed by the banks, while the commitment amount is the amount we asked the banks to commit to fund pursuant to the terms of the credit agreement. The banks have the option to participate in any borrowing request made by us in excess of the commitment amount, up to the borrowing base limit, although they are not obligated to fund any amount in excess of $100 million, the commitment amount. The advantage to us is that we will pay commitment fees on the commitment amount, not the borrowing base, thus lowering our overall cost of available credit.

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 for a minimum equity balance, (iii) a requirement to maintain positive working capital, as defined, (iv) a minimum interest coverage test and (v) a prohibition of most debt and corporate guarantees. We were in compliance with all of our bank covenants as of December 31, 2004. Our bank credit facility provides for a semi-annual re-determination of the borrowing base on April 1 and October 1. Borrowings under the credit facility are generally in tranches that can have maturities up to one year. Interest on any borrowings are based on the Prime Rate or LIBOR rate plus an applicable margin as determined by the borrowings outstanding. The facility matures in April 2009.

As of December 31, 2004, we had no outstanding borrowings under the facility and $460,000 in letters of credit secured by the facility. The next scheduled re-determination of the borrowing base will be as of April 1, 2005, based on December 31, 2004 assets and proved reserves.

SUBORDINATED DEBT ISSUANCE OF 7.5% SENIOR SUBORDINATED NOTES DUE 2013

On March 25, 2003, we issued $225 million of 7.5% Senior Subordinated Notes due 2013. The 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 existing $200 million of 9% Senior Subordinated Notes due 2008, including the Series B notes (see "Redemption of 9% Senior Subordinated Notes due 2008 (Including Series B Notes)" below).

The notes mature on April 1, 2013 and interest on the notes is payable each April 1 and October 1. We may redeem the 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. In addition, prior to April 1, 2006, we may redeem up to 35% of the notes at a redemption price of 107.5% with net cash proceeds from a stock offering. The indenture under which the notes were issued is essentially the same as the indenture covering our previously outstanding 9% notes. The indenture contains certain restrictions on our ability to incur additional debt, pay dividends

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 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 (see Note 1), we entered into a First Supplemental Indenture dated December 29, 2003, which did not require the consent of the holders of the 7.5% Senior Subordinated Notes due 2013. 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.

REDEMPTION OF 9% SENIOR SUBORDINATED NOTES DUE 2008 (INCLUDING SERIES B NOTES)

On April 16, 2003, we redeemed our $200 million of 9% Senior Subordinated Notes due 2008 at an aggregate cost of $209.0 million, including a $9.0 million call premium. As a result of this early redemption, we recorded a before-tax charge to earnings in the second quarter of 2003 of $17.6 million ($11.5 million after income tax), which included the $9.0 million call premium and the write-off of the remaining discount and debt issuance costs associated with these notes.

INDEBTEDNESS REPAYMENT SCHEDULE

As of December 31, 2004, our indebtedness, excluding the discount on our senior subordinated debt, is repayable over the next five years and thereafter as follows:

(IN THOUSANDS)	
2005	$ 375
2006	412
2007	451
2008	496
2009	545
Thereafter	227,280
Total indebtedness	$229,559

NOTE 7. INCOME TAXES

Our income tax provision (benefit) is as follows:

(IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2004	2003	2002
Current income tax expense (benefit):			
Federal	$ 22,166	$ (91)	$ (419)
State	763	–	13
Total current income tax expense (benefit)	22,929	(91)	(406)
Deferred income tax expense:			
Federal	12,352	23,864	21,822
State	4,111	2,439	2,104
Total deferred income tax expense	16,463	26,303	23,926
Total income tax expense	$39,392	$ 26,212	$23,520

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. Our current income tax benefit in 2002 is primarily related to tax law changes in 2002 that allowed us to receive a refund of our alternative minimum taxes paid for 2001. At December 31, 2004, we have approximately $132.3 million in state net operating loss carryforwards that begin to expire in 2013. In 2001, we began to recognize a benefit for the amount of enhanced oil recovery credits earned from our tertiary recovery projects. The total credits earned to date are approximately $27.8 million. These credits 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, 2004 and 2003 balance sheet dates. We believe that we will be able to utilize all of our deferred tax assets at December 31, 2004, and therefore have provided no

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

valuation allowance against our deferred tax assets. At December 31, 2004 and 2003, our deferred tax assets and liabilities were as follows:

(IN THOUSANDS)	DECEMBER 31, 2004	DECEMBER 31, 2003
Deferred tax assets:		
Loss carryforwards – federal	$ –	$33,234
Loss carryforwards – state	5,290	2,764
Tax credit carryover	14,186	978
Enhanced oil recovery credit carryforwards	27,828	16,578
Derivative hedging contracts	2,920	16,617
Other	318	90
Total deferred tax assets	50,542	70,261
Deferred tax liabilities:		
Property and equipment	(120,038)	(112,200)
Asset retirement obligations	(2,440)	(1,600)
Total deferred tax liabilities	(122,478)	(113,800)
Total net deferred tax liability	$ (71,936)	$ (43,539)

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, 2004	2003	2002
Income tax provision calculated using the federal statutory income tax rate	$42,644	$28,054	$24,587
State income taxes	4,874	2,398	2,121
Enhanced oil recovery credits	(7,986)	(4,687)	(3,394)
Other	(140)	447	206
Total income tax expense	$39,392	$ 26,212	$23,520

Note 8. Stockholders' Equity

AUTHORIZED

We are authorized to issue 100 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

Since August 2003, Denbury has 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). The Plan provides for purchases through an independent broker of 50,000 shares of Denbury's common stock per fiscal quarter over a period of approximately twelve months, or a total of 200,000 shares per year. Purchases are to be made at prices and times determined at the discretion of the independent broker, provided however that no purchases may be made during the last ten business days of a fiscal quarter. During 2003, we purchased 100,000 shares at an average cost of $12.77 per share and reissued 91,838 of those shares under Denbury's Employee Stock Purchase Plan. In 2004, we repurchased into treasury 200,000 shares at an average cost of $19.89 per share and reissued 115,090 treasury shares under the Employee Stock Purchase Plan. Our current repurchase program extends through June 2005.

STOCK OPTION PLANS

Denbury has two stock option plans in effect at December 31, 2004. The first plan has been in existence since 1995 (the "1995 Plan") and will expire in August 2005. The second plan, the 2004 Omnibus Stock and Incentive Plan (the "2004 Plan"), has a ten year term and was approved by the shareholders in May 2004. At December 31, 2004, we had a total of 8,195,587 shares of common stock authorized for issuance pursuant to the 1995 Plan, of which 710,291 shares were available for issuance, and 1,125,000 shares authorized for issuance pursuant to the 2004 Plan, of which all 1,125,000 were available for issuance. In January 2005, we issued options under the 1995 Plan that utilized substantially all of the remaining shares under the 1995 Plan and that same month began issuing options under the 2004 Plan. We do not anticipate issuing any further options pursuant to the 1995 Plan and all future grants will be made pursuant to the 2004 Plan. Under the terms of these plans, incentive and non-qualified options may be issued to officers, employees, directors and consultants.

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Options generally become exercisable over a four-year vesting period with the specific terms of vesting determined by the board of directors at the time of grant. The options expire over terms not to exceed ten 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 options are granted at the fair market value at the time of grant, which is generally defined in the 1995 Plan as the average closing price of our common stock for the ten trading days prior to issuance, or in the case of the 2004 Plan, the closing price on the date of grant. These plans are administered by the Compensation Committee of Denbury's Board of Directors.

The following is a summary of our stock option activity:

	YEAR ENDED DECEMBER 31,					
	2004		2003		2002	
	NUMBER OF OPTIONS	WEIGHTED AVERAGE PRICE	NUMBER OF OPTIONS	WEIGHTED AVERAGE PRICE	NUMBER OF OPTIONS	WEIGHTED AVERAGE PRICE
Outstanding at beginning of year	5,326,216	$ 9.20	4,996,365	$ 8.46	4,615,223	$ 8.40
Granted	1,009,810	14.35	957,608	11.33	921,341	7.50
Exercised	(1,264,284)	8.49	(550,090)	5.77	(370,120)	4.51
Forfeited	(631,585)	9.77	(77,667)	12.25	(170,079)	10.30
Outstanding at end of year	4,440,157	10.49	5,326,216	9.20	4,996,365	8.46
Exercisable at end of year	1,544,412	$ 9.61	2,263,264	$ 10.11	2,267,230	$10.26

The following is a summary of stock options outstanding at December 31, 2004:

	OPTIONS OUTSTANDING			OPTIONS EXERCISABLE	
RANGE OF EXERCISE PRICES	NUMBER OF OPTIONS OUTSTANDING AT 12/31/04	WEIGHTED AVERAGE REMAINING CONTRACTUAL LIFE	WEIGHTED AVERAGE EXERCISE PRICE	NUMBER OF OPTIONS EXERCISABLE AT 12/31/04	WEIGHTED AVERAGE EXERCISE PRICE
$3.77 – 5.50	689,338	4.4 years	$ 4.14	689,338	$ 4.14
$5.51 – 8.00	728,514	6.6 years	7.10	81,842	7.13
$8.01 – 11.50	1,459,336	7.1 years	10.37	134,839	9.69
$11.51 – 14.50	1,159,516	7.1 years	13.56	332,448	13.37
$14.51 – 22.50	361,443	4.0 years	18.33	305,945	18.48
$22.51 – 29.50	42,010	9.8 years	25.05	—	—
	4,440,157	6.4 years	10.49	1,544,412	9.61

RESTRICTED STOCK

During August through December 2004, the Board of Directors, based on a recommendation by the Board's Compensation Committee, awarded the officers of Denbury a total of 1,100,000 shares of restricted stock and the independent directors of Denbury a total of 50,000 shares of restricted stock, all granted under Denbury's 2004 Omnibus Stock and Incentive Plan that was approved by Denbury's shareholders in May 2004. 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 1,100,000 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 50,000 restricted shares issued to Denbury's independent board members, the shares vest 20% per year over five years. For these 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. All restricted shares vest upon death, disability or a change in control.

Upon issuance of the 1,150,000 shares of restricted stock pursuant to the 2004 Omnibus Stock and Incentive Plan, we recorded deferred compensation expense of $23.3 million, the market value of the shares on the grant dates, as a reduction to shareholders' equity. This expense will be amortized over the applicable five year or retirement date vesting periods. The compensation expense recorded with respect to the restricted shares for the year ending December 31, 2004, was $1.6 million.

EMPLOYEE STOCK PURCHASE PLAN

We have a Stock Purchase Plan that is authorized to issue up to 1,750,000 shares of common stock to all full-time employees. As of December 31, 2004, there are 291,376 authorized shares remaining to be issued under the plan. In accordance with the plan, 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 $1,011,000, $997,000 and $822,000 for the years ended December 31, 2004, 2003 and 2002, respectively. This plan is administered by the Compensation Committee of Denbury's Board of Directors. This plan currently terminates in August 2005, although we plan to request that shareholders extend this plan for another five years at the 2005 Annual Meeting of Shareholders.

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 2004, 2003 and 2002, Denbury's matching contributions were approximately $1.0 million, $1.1 million, and $884,000, respectively, to the 401(k) Plan.

NOTE 9. DERIVATIVE HEDGING CONTRACTS

We enter into various financial contracts to 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 historically consisted of price floors, collars and fixed price swaps. Historically, we have generally attempted to hedge between 50% and 75% of our anticipated production each year to provide us with a reasonably certain amount of cash flow to cover a majority of our budgeted exploration and development expenditures without incurring significant debt, although our hedging percentage may vary relative to our debt levels. 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. Our recent hedging activity has been predominantly with collars, although for the 2002 COHO acquisition, we also used swaps in order to lock in the prices used in our economic forecasts. 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 gain (loss) on our commodity contracts that qualify for hedge accounting which are included in "(Gain) loss on effective hedge contracts" in our Consolidated Statements of Operations:

	YEAR ENDED DECEMBER 31,		
(IN THOUSANDS)	2004	2003	2002
Settlement of hedge contracts – Oil	$(50,072)	$(20,337)	$ (598)
Settlement of hedge contracts – Gas	(20,397)	(41,873)	1,530
Gain (loss) on effective hedge contracts	$(70,469)	$ (62,210)	$ 932

The following is a summary of "(Gain) loss on ineffective hedge contracts," included in our Consolidated Statements of Operations:

	YEAR ENDED DECEMBER 31,		
(IN THOUSANDS)	2004	2003	2002
Settlement of contract not qualifying for hedge accounting	$14,088	$ —	$ —
Hedge ineffectiveness on contracts qualifying for hedge accounting	2,687	282	600
Reclassification of accumulated other comprehensive income balance and adjustments to fair value associated with termination of contracts designated to offshore production	(955)	—	—
Adjustments to fair value and amortization of ineffective hedge no longer qualifying for hedge accounting	2,086	—	—
Adjustment to fair value associated with contracts transferred in sale of offshore properties	(2,548)	—	
Amortization of contract premiums	—	1,192	9,664
Amortization of terminated Enron-related hedges over the original contract periods	—	(5,052)	(13,357)
(Gain) loss on ineffective contracts	$ 15,358	$(3,578)	$ (3,093)

LOSS ON ENRON HEDGES

In conjunction with the acquisition of Matrix Oil and Gas, Inc. in July 2001, we purchased commodity hedges to protect our investment. These hedges, in the form of price floors, covered nearly all of the forecasted production from the acquired properties through the end of 2003 at floor prices ranging from $3.75 to $4.25 per MMBtu. Due to the falling natural gas prices in the latter half of 2001, we collected approximately $12.7 million on these hedges. The price floors relating to 2002 and 2003 were purchased from Enron Corporation, which filed bankruptcy in December 2001. We sold our bankruptcy claim against Enron in February 2002 for net proceeds of approximately $9.2 million. In total, we collected approximately

$21.9 million from the price floors relating to the Matrix acquisition, resulting in a net cash gain of approximately $3.9 million over the cost of the floors. Because of the rise in natural gas prices after December 2001, we would not have collected anything on the price floors relating to 2003, even if Enron had not filed bankruptcy, as the natural gas NYMEX prices during 2003 were above $3.75 (the floor price for 2003). We calculate that our total cash loss due to Enron's bankruptcy was approximately $5.4 million, representing the difference between what we would have collected during 2002 and the $9.2 million that we obtained from selling the bankruptcy claim.

When Enron filed for bankruptcy during the fourth quarter of 2001, these Enron hedges ceased to qualify for hedge accounting treatment, which changed the accounting treatment for those hedges as of that point in time as required by SFAS No. 133. The result was that any future changes in the current market value of these assets had to be reflected in the income statement and any remaining accumulated other comprehensive income at the time of the accounting change had to be recognized over the original expected life of the hedges. To adjust the value of the Enron hedges down to the market value at December 31, 2001, which was determined to be the amount that we received from the sale of our claims in February 2002, we recorded a pre-tax write-down of $24.4 million in the fourth quarter of 2001. We also had a claim against Enron for production receivables relating to November 2001 natural gas production that was also sold in February 2002, which resulted in an overall total pre-tax loss on our Enron related assets of $25.2 million. The after-tax balance in accumulated other comprehensive income related to these Enron hedges was approximately $11.6 million at the point they no longer qualified for hedge accounting. Accordingly, we recognized pre-tax income attributable to the Enron hedges during 2002 of approximately $13.4 million and recognized pre-tax income during 2003 of approximately $5.1 million. The three-year total pre-tax net loss on the Enron hedges was approximately $5.9 million, which approximates the difference between the amount collected and paid for the Enron portion of the associated price floors.

HEDGING CONTRACTS AT DECEMBER 31, 2004

CRUDE OIL CONTRACTS:

	NYMEX CONTRACT PRICES PER BBL				ESTIMATED FAIR VALUE AT DECEMBER 31, 2004 (IN THOUSANDS)
			COLLAR PRICES		
TYPE OF CONTRACT AND PERIOD	BBLS/D	FLOOR PRICE	FLOOR	CEILING	
Floor Contracts					
Jan. 2005 – Dec. 2005	7,500	$27.50	—	—	$ 949

NATURAL GAS CONTRACTS:

	NYMEX CONTRACT PRICES PER MMBTU				ESTIMATED FAIR VALUE AT DECEMBER 31, 2004 (IN THOUSANDS)
			COLLAR PRICES		
TYPE OF CONTRACT AND PERIOD	MMBTU/D	FLOOR PRICE	FLOOR	CEILING	
Collar Contracts					
Jan. 2005 – Dec. 2005	15,000	—	$3.00	$5.50	$(5,815)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

At December 31, 2004, our derivative contracts were recorded at their fair value, which was a net liability of $4.9 million. To the extent our hedges are considered effective, this fair value liability, net of income taxes, is included in Accumulated other comprehensive income (loss) reported under Stockholders' equity in our Consolidated Balance Sheets. The balance in accumulated other comprehensive loss of $4.8 million at December 31, 2004, represents the deficit in the fair market value of our derivative contracts as compared to the cost of our hedges, net of income taxes. The $4.8 million in accumulated other comprehensive loss as of December 31, 2004, will expire within the next 12 months.

We have decided to de-designate from hedge accounting treatment our existing derivative hedging instruments, effective January 1, 2005. As such, we will account for our derivative instruments in future periods as speculative contracts and future changes in the fair value of these instruments will be recognized in the income statement in the period of change. While this may result in more volatility in our income statement in future periods, we believe that the benefits associated with applying hedge accounting do not outweigh the cost, time and effort required to apply hedge accounting.

Note 10. Commitments and Contingencies

We have operating leases for the rental of office space, equipment, and vehicles that totaled $21.6 million, $16.6 million, and $1.7 million as of December 31, 2004, 2003, and 2002, respectively. In addition, in 2004 we entered into two lease financing arrangements totaling $6.9 million for equipment at our McComb Field and Jackson Dome CO_2 Field. These lease terms are for seven years with monthly payments of approximately $91,000 per month. In August 2003, we entered into a $6.0 million lease financing arrangement for certain equipment at our CO_2 processing facility at Mallalieu Field. This lease term is for seven years with monthly payments of approximately $81,000 per month.

In 2004, we entered into two 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, 2004, long-term commitments for these items require the following future minimum rental payments:

(IN THOUSANDS)	CAPITAL LEASES	OPERATING LEASES
2005	$ 806	$ 3,977
2006	806	3,967
2007	806	3,954
2008	806	3,807
2009	806	3,064
Thereafter	2,777	2,813
Total minimum lease payments	6,807	$21,582
Less: Amount representing interest	(2,248)	
Present value of minimum lease payments	$ 4,559	

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 two CO_2 volumetric production payments (see "Genesis Transactions" above). Based upon the maximum amounts deliverable as stated in the contracts and the volumetric production payment, we estimate that we may be obligated to deliver up to 398 Bcf of CO_2 to these customers over the next 17 years; however, since the group as a whole has historically purchased less CO_2 than the maximum allowed in their contracts, based on the current level of deliveries, we project that our commitment would likely be reduced to approximately 332 Bcf. The maximum volume required in any given year is approximately 101 MMcf/d, although based on our current level of deliveries, this would likely be reduced to approximately 78 MMcf/d. Given the size of our proven CO_2 reserves at December 31, 2004 (approximately 2.7 Tcf before deducting approximately 178.7 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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, including those noted below. 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. The estimate of the potential impact from the following legal proceedings on our financial position or overall results of operations could change in the future.

Along with two other companies, we have been named in a lawsuit styled *J. Paulin Duhe, Inc. vs. Texaco, Inc., et al*, Cause No. 101,227, filed in late 2003 in the 16th Judicial District Court, Division "E," Terrebonne Parish, Louisiana, seeking restoration to its original condition of property on which oil has been produced over the past 70 years. The contract and tort claims by the plaintiffs allege surface and groundwater damage of 26 acres that are part of our Iberia Field in Iberia Parish, Louisiana. Recently, plaintiff's experts have initially alleged that clean-up of alleged contamination of the property would cost $79.0 million, although settlement offers by plaintiffs have already been made for much smaller sums. The property was originally leased to Texaco, Inc. for mineral development in 1934 and Denbury acquired its interest in the property in August 2000 from Manti Operating Company. Discovery is currently underway, and the April 2005 trial setting has been continued to an unspecified date in the future. We believe that we are indemnified by the prior owner, which we expect to cover our exposure to most damages, if any, found to have occurred prior to the time that we purchased the property. We believe that the allegations of this lawsuit are subject to a number of defenses, are without merit and we and the other defendants plan to vigorously defend this lawsuit, and if necessary, we will seek indemnification from the prior owner.

On December 29, 2003, an action styled *Harry Bourg Corporation vs. Exxon Mobil Corporation, et al*, Cause No. 140749, was filed in the 32nd Judicial District Court, Terrebonne Parish, Louisiana against Denbury and eleven other oil companies and their predecessors alleging damage as the result of mineral exploration activities conducted by these oil and gas operators/companies over the last 60 years. Plaintiff has asked for restoration of the 10,000 acre property and/or damages in claims made under tort law and various oil and gas contracts. The Bourg Corporation recently produced its first preliminary expert reports that allege damages of approximately $100.0 million against Denbury. Discovery is continuing in this case, with trial currently set for January 2006. We believe the allegations of this lawsuit are without merit and plan to vigorously defend this lawsuit along with the other defendants. No provision has been accrued in our financial statements.

Note 11. 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, 2004, two purchasers each accounted for 10% or more of our oil and natural gas revenues: Hunt Refining (21%) and Genesis (14%). For the year ended December 31, 2003, we had two significant purchasers that each accounted for 10% or more of our oil and natural gas revenues: Hunt Refining (15%) and Genesis

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(12%). For the year ended December 31, 2002, two purchasers each accounted for 10% or more of our natural gas revenues: Hunt Refining (14%) and Genesis (11%).

ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

(IN THOUSANDS)	DECEMBER 31, 2004	2003
Accounts payable	$26,262	$ 33,321
Accrued compensation	5,613	2,806
Accrued exploration and development costs	5,439	7,546
Accrued interest	4,219	4,272
Asset retirement obligations – current	2,596	2,101
Deferred revenues – Genesis	2,431	2,105
Advances payable	76	4,430
Other	5,224	5,768
Total	$ 51,860	$62,349

SUPPLEMENTAL CASH FLOW INFORMATION

(IN THOUSANDS)	DECEMBER 31, 2004	2003	2002
Interest paid	$18,099	$23,525	$24,636
Income taxes paid (refunded)	20,726	184	(1,304)

In 2004, we recorded a non-cash increase to property and debt in the amount of $4.6 million in connection with two capital leases. In August through December 2004, the company issued 1,150,000 shares of restricted stock with a market value of $23.3 million on the date of grant. See Note 8 – Stockholders' Equity-Restricted Stock.

FAIR VALUE OF FINANCIAL INSTRUMENTS

	DECEMBER 31, 2004		2003	
(IN THOUSANDS)	CARRYING AMOUNT	ESTIMATED FAIR VALUE	CARRYING AMOUNT	ESTIMATED FAIR VALUE
Senior bank debt	$ —	$ —	$ 75,000	$ 75,000
7.5% Senior Subordinated Notes due 2013	223,397	243,000	223,203	232,875

As of December 31, 2003, the carrying value of our bank debt approximated fair value based on the fact that our bank debt is subject to short-term floating interest rates that approximated the rates available to us at those periods. The fair values of our senior subordinated notes are based on quoted market prices. The fair values of our short-term investments are discussed in Note 1. We have other financial instruments consisting primarily of cash, cash equivalents, short-term receivables and payables that approximate fair value due to the nature of the instrument and the relatively short maturities.

Note 12. Condensed Consolidating Financial Information

On December 29, 2003, we amended the indenture for our 7.5% Senior Subordinated Notes due 2013 to reflect our new holding company organizational structure (see Note 1 and Note 6). As part of this restructuring our indenture was amended so that both Denbury Resources Inc. and Denbury Onshore, LLC became co-obligors of our subordinated debt. Prior to this restructure, Denbury Resources Inc. was the sole obligor. Our subordinated debt is fully and unconditionally guaranteed by Denbury Resources Inc.'s significant subsidiaries. Genesis Energy, Inc., the subsidiary that holds the Company's investment in Genesis Energy, L.P., is not a guarantor of our subordinated debt. The results of our equity interest in

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Genesis is reflected through the equity method by one of our significant subsidiaries, Denbury Gathering & Marketing. The following is condensed consolidating financial information for Denbury Resources Inc., Denbury Onshore, LLC, and significant subsidiaries:

CONDENSED CONSOLIDATING BALANCE SHEETS

	DECEMBER 31, 2004				
(IN THOUSANDS)	DENBURY RESOURCES INC. (PARENT AND CO-OBLIGOR)	DENBURY ONSHORE, LLC (ISSUER AND CO-OBLIGOR)	GUARANTOR SUBSIDIARIES	ELIMINATIONS	DENBURY RESOURCES INC. CONSOLIDATED
Assets					
Current assets	$ 1	$ 171,997	$204,709	$ (203,861)	$ 172,846
Property and equipment	—	796,578	784	—	797,362
Investment in subsidiaries (equity method)	541,671	—	333,907	(868,787)	6,791
Other assets	—	15,707	2,271	(2,271)	15,707
Total assets	$ 541,672	$984,282	$ 541,671	$(1,074,919)	$992,706
Liabilities and Stockholders' Equity					
Current liabilities	$ —	$286,767	$ —	$ (203,861)	$ 82,906
Long-term liabilities	—	370,399	—	(2,271)	368,128
Stockholders' equity	541,672	327,116	541,671	(868,787)	541,672
Total liabilities and stockholders' equity	$ 541,672	$984,282	$ 541,671	$(1,074,919)	$992,706

	DECEMBER 31, 2003				
(IN THOUSANDS)	DENBURY RESOURCES INC. (PARENT AND CO-OBLIGOR)	DENBURY ONSHORE, LLC (ISSUER AND CO-OBLIGOR)	GUARANTOR SUBSIDIARIES	ELIMINATIONS	DENBURY RESOURCES INC. CONSOLIDATED
Assets					
Current assets	$ 1	$ 85,109	$ 23,045	$ —	$ 108,155
Property and equipment	—	560,038	292,473	—	852,511
Investment in subsidiaries (equity method)	421,201	—	210,803	(624,554)	7,450
Other assets	—	11,186	3,319	—	14,505
Total assets	$421,202	$656,333	$529,640	$ (624,554)	$ 982,621
Liabilities and Stockholders' Equity					
Current liabilities	$ —	$ 119,364	$ 7,210	$ —	$126,574
Long-term liabilities	—	333,616	101,229	—	434,845
Stockholders' equity	421,202	203,353	421,201	(624,554)	421,202
Total liabilities and stockholders' equity	$421,202	$656,333	$529,640	$ (624,554)	$ 982,621

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

	YEAR ENDED DECEMBER 31, 2004				
(IN THOUSANDS)	DENBURY RESOURCES INC. (PARENT AND CO-OBLIGOR)	DENBURY ONSHORE, LLC (ISSUER AND CO-OBLIGOR)	GUARANTOR SUBSIDIARIES	ELIMINATIONS	DENBURY RESOURCES INC. CONSOLIDATED
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	(65)	30,082	9,375	—	39,392
Net income (loss)	$82,448	$67,258	$ 82,554	$(149,812)	$ 82,448

	YEAR ENDED DECEMBER 31, 2003				
(IN THOUSANDS)	DENBURY RESOURCES INC. (PARENT AND CO-OBLIGOR)	DENBURY ONSHORE, LLC (ISSUER AND CO-OBLIGOR)	GUARANTOR SUBSIDIARIES	ELIMINATIONS	DENBURY RESOURCES INC. CONSOLIDATED
Revenues	$ —	$238,072	$ 94,942	$ —	$333,014
Expenses	—	196,392	56,725	—	253,117
Income before the following:	—	41,680	38,217	—	79,897
Equity in net earnings of subsidiaries	56,553	—	40,667	(96,964)	256
Income before income taxes and cumulative effect of change in accounting principle	56,553	41,680	78,884	(96,964)	80,153
Income tax provision	—	5,250	20,962	—	26,212
Net income before cumulative effect of change in accounting principle	56,553	36,430	57,922	(96,964)	53,941
Cumulative effect of a change in accounting principle, net of income tax	—	3,981	(1,369)	—	2,612
Net income (loss)	$ 56,553	$ 40,411	$ 56,553	$ (96,964)	$ 56,553

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

CONDENSED CONSOLIDATING STATEMENTS OF *OPERATIONS* (CONTINUED)

	YEAR ENDED DECEMBER 31, 2002			
(IN THOUSANDS)	DENBURY RESOURCES INC. (PARENT AND ISSUER)	GUARANTOR SUBSIDIARIES	ELIMINATIONS	DENBURY RESOURCES INC. CONSOLIDATED
Revenues	$231,147	$54,005	$ —	$285,152
Expenses	166,805	48,087	—	214,892
Income before the following:	64,342	5,918	—	70,260
Equity in net earnings of subsidiaries	3,456	55	(3,456)	55
Income (loss) before income taxes	67,798	5,973	(3,456)	70,315
Income tax provision	21,003	2,517	—	23,520
Net income (loss)	$ 46,795	$ 3,456	$(3,456)	$ 46,795

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

	YEAR ENDED DECEMBER 31, 2004				
(IN THOUSANDS)	DENBURY RESOURCES INC. (PARENT AND CO-OBLIGOR)	DENBURY ONSHORE, LLC (ISSUER AND CO-OBLIGOR)	GUARANTOR SUBSIDIARIES	ELIMINATIONS	DENBURY RESOURCES INC. CONSOLIDATED
Cash flow from operations	$(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 (decrease) in cash flow	—	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

	YEAR ENDED DECEMBER 31, 2003				
(IN THOUSANDS)	DENBURY RESOURCES INC. (PARENT AND CO-OBLIGOR)	DENBURY ONSHORE, LLC (ISSUER AND CO-OBLIGOR)	GUARANTOR SUBSIDIARIES	ELIMINATIONS	DENBURY RESOURCES INC. CONSOLIDATED
Cash flow from operations	$ —	$146,639	$ 50,976	$ —	$ 197,615
Cash flow from investing activities	—	(81,256)	(54,622)	—	(135,878)
Cash flow from financing activities	1	(61,490)	—	—	(61,489)
Net increase (decrease) in cash flow	1	3,893	(3,646)	—	248
Cash, beginning of period	—	20,281	3,659	—	23,940
Cash, end of period	$ 1	$ 24,174	$ 13	$ —	$ 24,188

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS (CONTINUED)

	YEAR ENDED DECEMBER 31, 2002			
(IN THOUSANDS)	DENBURY RESOURCES INC. (PARENT AND ISSUER)	GUARANTOR SUBSIDIARIES	ELIMINATIONS	DENBURY RESOURCES INC. CONSOLIDATED
Cash flow from operations	$ 146,132	$ 13,468	$ —	$159,600
Cash flow from investing activities	(154,908)	(16,253)	—	(171,161)
Cash flow from financing activities	12,005	—	—	12,005
Net increase (decrease) in cash flow	3,229	(2,785)	—	444
Cash, beginning of period	17,052	6,444	—	23,496
Cash, end of period	$ 20,281	$ 3,659	$ —	$ 23,940

NOTE 13. 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:

	YEAR ENDED DECEMBER 31,		
(IN THOUSANDS)	2004	2003	2002
Property acquisitions:			
Proved	$ 22,271	$ 22,307	$ 56,364
Unevaluated	3,459	3,955	4,342
Exploration	23,987	34,050	29,985
Development	128,351	98,132	64,946
Asset retirement obligations	3,174	3,405	—
Total costs incurred (1)	$181,242	$161,849	$155,637

(1) Capitalized general and administrative costs that directly relate to exploration and development activities were $5.1 million, $5.5 million, $5.3 million for the years ended December 31, 2004, 2003 and 2002, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

OIL AND NATURAL GAS OPERATING RESULTS

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

	YEAR ENDED DECEMBER 31,		
(IN THOUSANDS, EXCEPT PER BOE DATA)	2004	2003	2002
Oil, natural gas and related product sales	$444,777	$385,463	$274,894
Gain (loss) on effective hedge contracts	(70,469)	(62,210)	932
Total revenues	374,308	323,253	275,826
Lease operating costs	87,107	89,439	71,188
Production taxes and marketing expenses	18,737	14,819	11,902
Depletion, depreciation and accretion	90,913	90,694	90,679
(Gain) loss on ineffective hedge contracts	15,358	(3,578)	(3,093)
Net operating income	162,193	131,879	105,150
Income tax provision	52,437	45,427	36,563
Results of operations from oil and natural gas producing activities	$109,756	$ 86,452	$ 68,587
Depletion, depreciation and accretion per BOE	$ 7.54	$ 7.16	$ 6.98

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 year. We also have a corporate policy whereby proved undeveloped reserves must be economic at prices significantly lower than the year-end prices used in our reserve report, at prices closer to historical averages.

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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

ESTIMATED QUANTITIES OF RESERVES

	YEAR ENDED DECEMBER 31,					
	2004		2003		2002	
	OIL (MBBL)	GAS (MMCF)	OIL (MBBL)	GAS (MMCF)	OIL (MBBL)	GAS (MMCF)
Balance at beginning of year	91,266	221,887	97,203	200,947	76,490	198,277
Revisions of previous estimates	(3,271)	2,898	2,958	(25,451)	(408)	(22,975)
Revisions due to price changes	492	25	50	(152)	3,020	2,660
Extensions and discoveries	1,575	61,158	1,059	68,408	2,326	51,819
Improved recovery (1)	18,863	—	4,009	—	—	—
Production	(7,044)	(30,094)	(6,896)	(34,623)	(6,874)	(36,662)
Acquisition of minerals in place	429	5,304	838	14,541	23,383	9,360
Sales of minerals in place	(1,023)	(92,694)	(7,955)	(1,783)	(734)	(1,532)
Balance at end of year	101,287	168,484	91,266	221,887	97,203	200,947
Proved Developed Reserves:						
Balance at beginning of year	53,804	144,750	62,398	142,812	54,722	169,897
Balance at end of year	55,998	94,573	53,804	144,750	62,398	142,812

(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 the reduced oil price 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,		
	2004	2003	2002
Oil (NYMEX)	$43.45	$32.52	$31.20
Natural Gas (NYMEX Henry Hub)	6.15	6.19	4.79

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

(IN THOUSANDS)	DECEMBER 31, 2004	2003	2002
Future cash inflows	$ 4,742,276	$4,059,424	$3,787,077
Future production costs	(1,509,280)	(1,120,741)	(1,044,193)
Future development costs	(340,879)	(300,981)	(268,269)
Future net cash flows before taxes	2,892,117	2,637,702	2,474,615
Future income taxes	(906,221)	(748,273)	(689,617)
Future net cash flows	1,985,896	1,889,429	1,784,998
10% annual discount for estimated timing of cash flows	(856,700)	(765,302)	(756,022)
Standardized measure of discounted future net cash flows	$ 1,129,196	$ 1,124,127	$1,028,976

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

(IN THOUSANDS)	YEAR ENDED DECEMBER 31, 2004	2003	2002
Beginning of year	$ 1,124,127	$1,028,976	$ 505,795
Sales of oil and natural gas produced, net of production costs	(339,250)	(281,205)	(191,803)
Net changes in sales prices	352,830	141,932	694,646
Extensions and discoveries, less applicable future development and production costs	151,014	235,228	151,926
Improved recovery [1]	190,033	40,663	—
Previously estimated development costs incurred	55,091	52,874	34,931
Revisions of previous estimates, including revised estimates of development costs, reserves and rates of production	(197,959)	(157,989)	(50,855)
Accretion of discount	156,637	142,622	57,433
Acquisition of minerals in place	9,003	44,856	160,899
Sales of minerals in place	(300,481)	(78,830)	(5,285)
Net change in income taxes	(71,849)	(45,000)	(328,711)
End of year	$ 1,129,196	$ 1,124,127	$1,028,976

(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 2.7 Tcf at December 31, 2004 (includes 178.7 Bcf of reserves dedicated to two volumetric production payments with Genesis), 1.6 Tcf at December 31, 2003 (includes 162.6 Bcf of reserves dedicated to a volumetric production payment), and 1.6 Tcf at December 31, 2002. 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 14. Unaudited Quarterly Information

IN THOUSANDS, EXCEPT PER SHARE AMOUNTS	MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER 31
2004				
Revenues [1]	$ 97,748	$ 106,213	$ 88,029	$ 90,982
Expenses [1]	64,710	77,277	61,886	57,123
Net income [2]	22,304	19,389	18,274	22,481
Net income per share:				
Basic	0.41	0.35	0.33	0.41
Diluted	0.40	0.34	0.32	0.39
Cash flow from operations	52,995	53,210	44,766	17,681
Cash flow provided by (used for) investing activities [2][3]	(68,111)	(51,351)	69,046	(43,134)
Cash flow provided by (used for) financing activities [2]	8,136	8,873	(84,035)	775
2003				
Revenues	$ 86,432	$ 84,188	$ 79,415	$ 82,979
Expenses [4]	58,910	76,660	56,691	60,856
Income before accounting change [5]	18,453	5,129	15,149	15,210
Net income [5]	21,065	5,129	15,149	15,210
Income per share before accounting change:				
Basic	0.34	0.10	0.28	0.28
Diluted	0.33	0.09	0.27	0.27
Net income per share:				
Basic	0.39	0.10	0.28	0.28
Diluted	0.38	0.09	0.27	0.27
Cash flow from operations	35,509	60,542	49,789	51,775
Cash flow used for investing activities	(18,139)	(54,742)	(35,495)	(27,502)
Cash flow provided by (used for) financing activities	119,860	(147,622)	(5,534)	(28,193)

(1) The loss on settlement of ineffective hedges has been reclassified from Revenues to Expenses in this presentation. For the second quarter of 2004, $3.5 million loss was reclassified from Revenues to Expenses. For the third quarter of 2004, $4.8 million loss was reclassified from Revenues to Expenses.

(2) In July 2004, we sold Denbury Offshore, Inc. a subsidiary that held our offshore assets. We used $85 million of the proceeds to retire debt (see Note 2).

(3) Auction rate securities in the amount of $35.4 million at September 30, 2004, have been reclassified from cash and equivalent to short-term investments to conform to the December 31, 2004 presentation. Accordingly, cash flow provided by investing activities for the quarter ended September 30, 2004 has been adjusted to reflect this presentation.

(4) In the second quarter of 2003, we incurred a $17.6 million ($11.5 million net of income tax) loss on early retirement of debt (see Note 6).

(5) In the first quarter of 2003, we recognized a gain of $2.6 million for the cumulative effect adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations" (see Note 4).

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

On May 12, 2004, the Audit Committee of Denbury approved the appointment of PricewaterhouseCoopers LLP as the Company's independent auditors for the fiscal year ending December 31, 2004, replacing Deloitte & Touche LLP, which had been the Company's independent auditors since 1990. This decision was affirmed by Denbury's Board of Directors. Information regarding this change in independent auditors was included in our report on Form 8-K dated May 17, 2004, and subsequently amended on May 24, 2004. There have been no other changes in accountants nor any disagreements with accountants.

ITEM 9A. 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 in all material respects in providing to them on a timely basis material information required to be disclosed in this annual report. Our assessment of our internal control over financial reporting as of December 31, 2004 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included in Item 8 herein.

There have been no changes in internal controls over financial reporting during the period covered by this annual report on Form 10-K that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

In January 2005, we began processing our transactions on a newly implemented accounting software system. We changed systems in order (i) to integrate and automate more of our functions, which will also allow us to have more information in one integrated database, (ii) to provide operating efficiencies, (iii) to enable us to close our books in a more timely manner without sacrificing quality, (iv) to review and improve our processes and (v) to improve the internal controls surrounding our computer systems. All of Denbury's 2004 accounting was performed on its prior system and as a result, this change had no impact on Denbury's internal controls over financial reporting during 2004. As a result of moving to a new system in January 2005, we anticipate that certain control procedures will need to be changed during 2005 in order to conform to our new system. We plan to evaluate those changes during the first quarter of 2005. While we believe that our new accounting system will ultimately strengthen our internal control system, there are inherent weaknesses in implementing any new system and until we have fully tested all changes to our controls, we may not be able to provide assurance that our disclosure controls are effective in all material respects.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE COMPANY

Directors of the Company

Information as to the names, ages, positions and offices with Denbury, terms of office, periods of service, business experience during the past five years and certain other directorships held by each director or person nominated to become a director of Denbury will be set forth in the "Election of Directors" segment of the Proxy Statement ("Proxy Statement") for the Annual Meeting of Shareholders to be held May 11, 2005, ("Annual Meeting") and is incorporated herein by reference.

Executive Officers of the Company

Information concerning the executive officers of Denbury will be set forth in the "Management" section of the Proxy Statement for the 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 not aware of any person who failed to file any reports required by Section 16(a) to be filed for fiscal 2004.

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 concerning remuneration received by Denbury's executive officers and directors will be presented under the caption "Statement of Executive Compensation" 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 Denbury's common stock that may be issued under our equity compensation plans, which plans have been approved by shareholders, and the number of shares of Denbury's common stock beneficially owned as of March 1, 2005, by each of its directors and nominees for director, its five most highly compensated executive officers and its directors and executive officers as a group will be presented under the captions "Equity Compensation Plan Information" and "Security Ownership of Certain Beneficial Owners and Management" in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information on related transactions will be presented under the caption "Compensation Committee Interlocks and Insider Participation" and "Interests of Insiders in Material Transactions" in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required to be presented on principal accountant fees and services will be presented under the caption "Relationship with Independent Accountants" in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

FINANCIAL STATEMENTS AND SCHEDULES. Financial statements and schedules filed as a part of this report are presented on page 50. 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)	Bylaws of Denbury Resources Inc., a Delaware corporation, adopted December 29, 2003 (incorporated by reference as Exhibit 3.2 of our Form 8-K filed December 29, 2003).
4(a)	Indenture for $225 million of 7.5% Senior Subordinated Notes due 2013 among Denbury Resources Inc., certain of its subsidiaries and JP Morgan Chase Bank as trustee, dated March 25, 2003 (incorporated by reference from Exhibit 4(a) to our Registration Statement No. 333-105233-04 on Form S-4, filed May 14, 2003).
4(b)	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 JP Morgan Chase Bank, as trustee (incorporated by reference as Exhibit 4.1 of our Form 8-K filed December 29, 2003).
10(a)	Fifth 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 September 1, 2004 (incorporated by reference as Exhibit 1.1 of our Form 8-K filed September 3, 2004).

EXHIBIT NO.	EXHIBIT
10(b)**	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(c)**	Denbury Resources Inc. Stock Purchase Plan (incorporated by reference as Exhibit 4(g) of the Registrant's 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).
10(d)**	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(e)**	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 and amended March 2, 2001).
10(f)**	Denbury Resources Severance Protection Plan, dated December 6, 2001 (incorporated by reference as Exhibit 10(f) of our Form 10-K for the year ended December 31, 2000).
10(g)* **	Denbury Resources Inc. 2004 Omnibus Stock and Incentive Plan as amended.
10(h)* **	Description of non-employee director's compensation arrangements.
10(i)* **	Description of cash bonus compensation arrangements for employees and officers.
10(j)* **	Description of stock option grant practices for employees and officers.
10(k)* **	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.
10(l)* **	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.
10(m)* **	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.
10(n)* **	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.
10(o)* **	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.

EXHIBIT NO.	EXHIBIT
10(p)* **	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.
10(q)* **	Form of non-qualified stock option agreement that 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.
10(r)* **	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 Stock and Incentive Plan for Denbury Resources Inc.
10(s)* **	Form of stock appreciation rights agreement that 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.
16	Letter from Deloitte & Touche LLP to the Securities and Exchange Commission, dated May 24, 2004, regarding change in certifying accountant, pursuant to Item 304(a)(3) of Regulation S-K (filed as exhibit 16.1 of our Form 8-K/A filed May 24, 2004).
21*	List of Subsidiaries of Denbury Resources Inc.
23(a)*	Consent of PricewaterhouseCoopers LLP.
23(b)*	Consent of Deloitte & Touche LLP.
23(c)*	Consent of DeGolyer and MacNaughton.
31(a)*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)*	Certification of Chief Financial Officer Pursuant to Section 302 of the 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, 2004, on oil and gas reserves (SEC Case) dated March 9, 2005.

*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. 3000, Plano, Texas 75024.

SIGNATURES

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

DENBURY RESOURCES INC.

/s/ Phil Rykhoek — March 11, 2005

Phil Rykhoek
Sr. Vice President and Chief Financial Officer

/s/ Mark C. Allen — March 11, 2005

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 — March 11, 2005

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

/s/ Phil Rykhoek — March 11, 2005

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

/s/ Mark C. Allen — March 11, 2005

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

/s/ Ron Greene — March 11, 2005

Ron Greene
Director

/s/ David I. Heather — March 11, 2005

David I. Heather
Director

/s/ Randy Stein — March 11, 2005

Randy Stein
Director

/s/ Wieland Wettstein — March 11, 2005

Wieland Wettstein
Director

/s/ Greg McMichael — March 11, 2005

Greg McMichael
Director

/s/ Donald Wolf — March 11, 2005

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   March 15, 2005

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 March 15, 2005

Phil Rykhoek
Sr. Vice President and Chief Financial Officer

CORPORATE INFORMATION

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

To receive a copy of Denbury Resource's Oil Game, please contact Laurie Burkes at laurie@denbury.com (Subject to availability.)

Officers

GARETH ROBERTS
President & C.E.O

TRACY EVANS
Senior Vice President
Reservoir Engineering

PHIL RYKHOEK
Senior Vice President & Chief Financial Officer

MARK WORTHEY
Senior Vice President
Operations

MARK ALLEN
Vice President & Chief Accounting Officer

RON GRAMLING
Vice President
Marketing

RAY DUBUISSON
Vice President
Land

JIM SINCLAIR
Vice President
Exploration

CORPORATE HEADQUARTERS
Denbury Resources Inc.
5100 Tennyson Pkwy, Ste. 3000
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
Jenkens & Gilchrist

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 the 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 certain exhibits. 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. We have included herein our Section 302 and 404 certifications by the CEO and CFO of our Form 10-K filed with the SEC.

ANNUAL MEETING
The annual meeting of stockholders will be held on May 11, 2005, at 3:00 P.M., local time, at the Denbury offices located at:

5100 Tennyson Pkwy, Ste. 3000
Plano, Texas 75024

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

DPI