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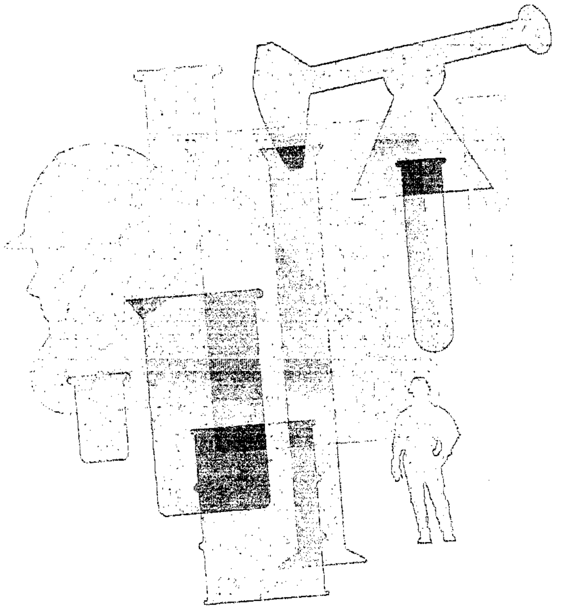
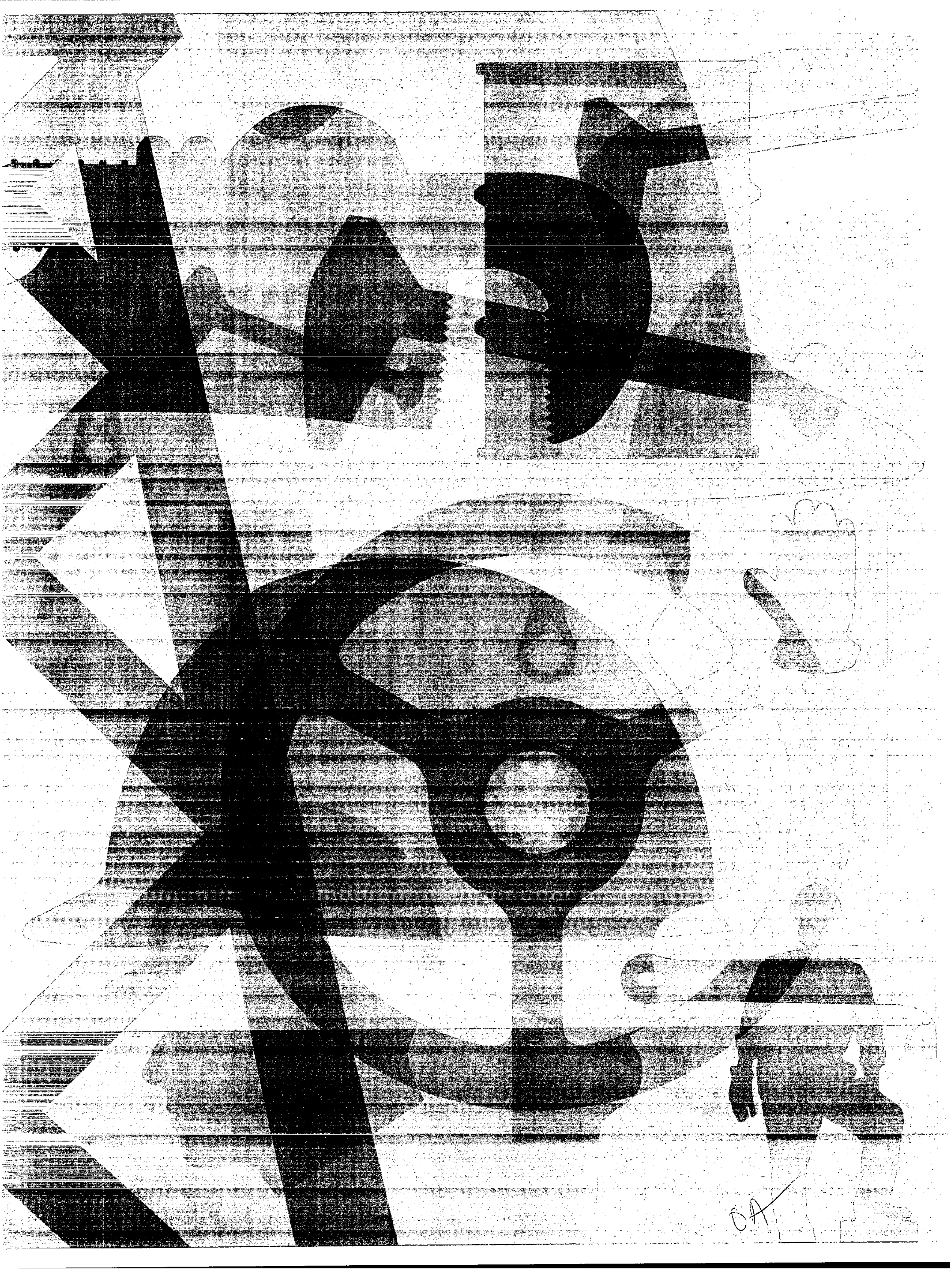
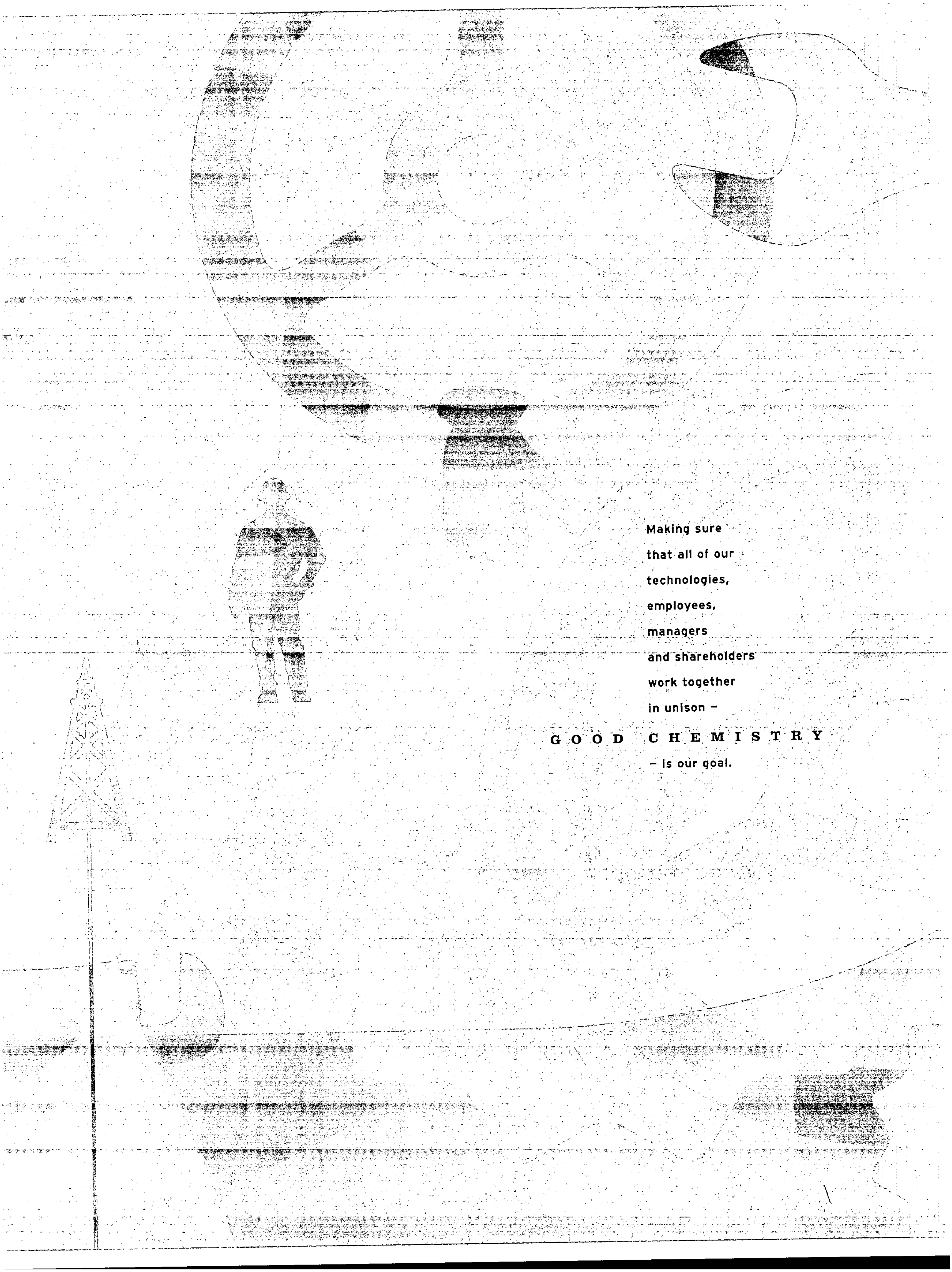


CHEMISTRY

Denbury Resources Inc. 2002 Annual Report




Making sure
that all of our
technologies,
employees,
managers
and shareholders
work together
in unison –
GOOD CHEMISTRY
– is our goal.

FINANCIAL HIGHLIGHTS

Amounts in thousands, unless otherwise noted

	Year Ended December 31,					
	2002	2001 [1]	2000	1999	1998	Average Annual Growth[2]
Production (daily)						
Oil (Bbls)	**18,833**	16,978	15,219	12,090	13,603	8 %
Natural gas (Mcf)	**100,443**	85,238	37,078	27,948	36,605	29 %
BOE (6:1)	**35,573**	31,185	21,399	16,748	19,704	16 %
Revenues	**285,152**	285,111	181,651	82,990	83,506	36 %
Unit sales price (excluding hedges)						
Oil (per Bbl)	**22.36**	21.34	25.89	15.03	10.29	21 %
Natural gas (per Mcf)	**3.31**	4.12	4.45	2.42	2.31	9 %
Unit sales price (including hedges)						
Oil (per Bbl)	**22.27**	21.65	23.50	13.08	10.29	21 %
Natural gas (per Mcf)	**3.35**	4.66	3.57	2.34	2.32	10 %
Cash flow from operations	**159,600**	185,047	95,972	41,200	20,285	67 %
Net income (loss) [3]	**46,795**	56,550	142,227	4,614	(287,145)	–
Average common shares outstanding						
Basic	**53,243**	49,325	45,823	39,928	25,926	20 %
Diluted	**54,365**	50,361	46,352	39,987	25,926	20 %
Net income (loss) per share						
Basic	**0.88**	1.15	3.10	0.12	(11.08)	–
Diluted	**0.86**	1.12	3.07	0.12	(11.08)	–
Oil and gas capital investments	**155,637**	327,175	134,021	54,967	102,652	11 %
CO_2 capital investments	**16,445**	45,555	–	–	–	–
Total assets	**895,292**	789,988	457,379	252,566	212,859	43 %
Long-term liabilities	**432,616**	360,882	202,428	154,976	226,436	18 %
Stockholders' equity (deficit) [4]	**366,797**	349,168	216,165	72,428	(32,265)	–
Proved reserves						
Oil (MBbls)	**97,203**	76,490	70,667	51,832	28,250	36 %
Natural gas (MMcf)	**200,947**	198,277	100,550	50,438	48,803	42 %
MBOE (6:1)	**130,694**	109,536	87,425	60,238	36,383	38 %
Discounted future cash flow – 10%	**1,426,220**	574,328	1,158,969	462,870	115,019	88 %
Per BOE data (6:1)						
Oil and natural gas revenues	**21.17**	22.88	26.13	14.88	11.36	17 %
Gain (loss) on settlements of derivative contracts	**0.07**	1.64	(3.23)	(1.54)	0.02	37 %
Lease operating expenses	**(5.48)**	(4.84)	(4.94)	(4.25)	(3.49)	12 %
Production taxes and marketing expenses	**(0.92)**	(0.96)	(1.02)	(0.60)	(0.56)	13 %
Production netback	**14.84**	18.72	16.94	8.49	7.33	19 %
CO_2 operating margin	**0.48**	0.38	–	–	–	–
General and administrative expense	**(0.96)**	(0.89)	(1.09)	(1.21)	(1.02)	-2 %
Net cash interest expense	**(1.73)**	(1.74)	(1.54)	(2.22)	(2.13)	-5 %
Current income taxes and other	**0.04**	(0.06)	(0.07)	0.11	–	–
Changes in assets and liabilities	**(0.38)**	(0.15)	(1.99)	1.57	(1.36)	–
Cash flow from operations	**12.29**	16.26	12.25	6.74	2.82	44%

(1) We acquired Matrix Oil and Gas, Inc. in July 2001. See Note 2 to the Consolidated Financial Statements.
(2) Four-year compounded annual growth rate computed using 1998 as a base year.
(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. In 1998, we recorded a $280.0 million writedown of our oil and natural gas properties under the full cost ceiling test.
(4) 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.

MESSAGE TO THE SHAREHOLDERS

Denbury had another excellent year during 2002. We increased our average production rate to 35,573 BOE/d and replaced 263% of our production at a finding cost of $4.43 per BOE. More importantly we acquired two key fields in our tertiary carbon dioxide play in West Mississippi, both with significant oil reserve potential. Our financial results continued to be strong, anchored by a 14% increase in average production year-over-year. Even though average natural gas prices were lower in 2002 than in 2001, our discretionary cash flow of $164.6 million, coupled with $7.7 million of proceeds from property sales, funded 100% of our total capital expenditures of $172.1 million. These expenditure included $56.4 million of oil and natural gas property acquisitions, the largest of which was the $48.2 million acquisition of properties from the COHO bankruptcy auction. Also included in the expenditure total is $16.4 million relating to acquisitions and development at Jackson Dome, the source of our carbon dioxide. The net result was solid earnings for the third straight year of $46.8 million or $0.88 per common share.

figure 1: Gareth Roberts, President and Chief Executive Officer

Our Strategy

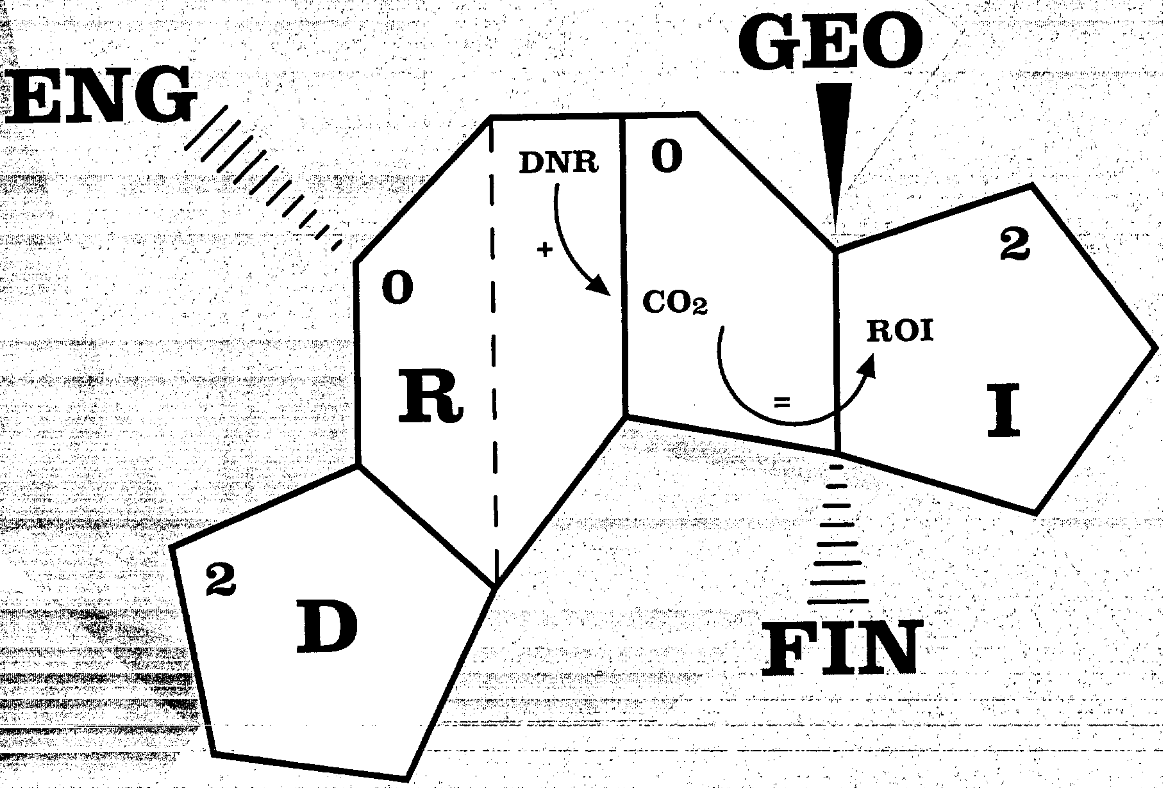
Denbury's strategy is to maintain a balanced portfolio of oil and natural gas investment opportunities covering a variety of risks, including both geology and commodities. Our portfolio is anchored by lower risk oil reserves that can be added through CO_2 tertiary flooding of depleted oil reservoirs, a feature that is unique to Denbury in the Gulf Coast Region. The varied geology of Mississippi, South Louisiana and offshore provides us with a range of low to high risk conventional drilling opportunities. Typically no more than 15-20% of our budget is allocated to high risk exploration. Our current production is almost equally split between oil and natural gas, a deliberate attempt by us to help reduce price risk on any single commodity. Our goal is to add reserves at an average cost of around $6.00 per BOE, which assumes that we can add oil reserves in our tertiary recovery play at around $4.00 per barrel, combined with the likelihood that our natural gas reserve costs will be above $6.00 per BOE.

"Our portfolio is anchored by lower risk oil reserves that can be added through CO_2 tertiary flooding of depleted oil reservoirs, a feature that is unique to Denbury in the Gulf Coast Region."

From a financial perspective, since 1999 we have followed a policy of spending no more than our cash flow on normal capital expenditures, excluding acquisitions. When we make significant acquisitions that require us to use additional debt, we typically protect that investment by hedging two to three years of production related to the acquisition. We have used other hedges, typically floors or collars, to *figure 2:* People and skills combine to make a

W I N N I N G F O R M U L A

for Denbury Resources.



protect against the downside price fluctuations and give us reasonable assurance of some minimum level of cash flow to fund our operations. During 2001 and 2002, we hedged between 70% and 80% of our total production with a combination of swaps, floors and collars.

During the last four years, we have been able to improve our credit statistics and relative debt levels by following these principles. At year end 2002, our total debt stood at $350 million, but was reduced to $325 million by late February 2003 following our sale of Laurel Field. Our goal is to reduce debt to $300 million during 2003, to give us a debt-to-capitalization ratio of approximately 44% and reduce our debt to no more than two times our estimated cash flow, assuming moderate oil and natural gas prices. We are proud of our results during the last few years and believe we are performing in the upper tier of our industry. Results can be measured in traditional ways, such as production growth, reserve growth and finding costs, but we focus evaluation of our progress on the growth in our proven net asset value per share using constant prices. By this measure, Denbury has increased its proven net asset value per share at a compounded growth rate of 20% over the past three years, which we believe is also in the upper tier of our industry.

figure 3: Phil Rykhoek, Senior Vice President and Chief Financial Officer

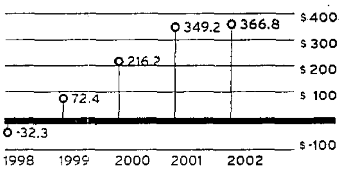
Our Strategy to Build Shareholder Value

In last year's annual report, we addressed several issues that investors and shareholders felt were affecting our valuation. We believe we made significant progress during 2002, as evidenced by a 50% increase in the value of our stock over the year. In each area more work remains to be done and management's goal in 2003 is to remain focused on these issues and to do our best to cause our performance to positively impact our stock price. To recap, the main concerns expressed to us were:

Comment: "The Company has a history of high priced acquisitions"

Response: Five years have passed since the expensive Heidelberg acquisition. We have continued to make acquisitions since then, the biggest of which in 2002 was the purchase of the COHO Mississippi properties. We purchased approximately 15 million barrels for an average cost of around $3.25 per Bbl, not including the potential 20 million Bbls of upside we expect to obtain by CO_2 flooding Brookhaven

Stockholders' Equity
In thousands of dollars



Field. The 2002 acquisition of McComb Field for $2.3 million was another solid, low cost, purchase, with 8.3 million Bbls of proven reserves as of year-end 2002. Our natural gas properties in Thornwell Field acquired during 2000 and the offshore natural gas properties acquired from Matrix in 2001 continue to add reserves and are far from fully exploited, and at today's natural gas prices are producing significant cash flow. We believe we have been disciplined in our recent acquisitions and no longer believe that this comment is warranted.

figure 4: Tracy Evans, Senior Vice President, Reservoir Engineering

Comment: "The Company and its share float are too small"

Response: Our enterprise value has increased to almost one billion dollars as a result of the improvement in our share price. If we continue to perform, this issue should resolve itself. During recent months, the Texas Pacific Group, our largest shareholder, sold 10.0 million shares, reducing their ownership to 32% from 52%. This had the benefit of increasing our public float and almost doubling our average daily trading volume. We appreciate TPG's support over the years and what they have done to help Denbury.

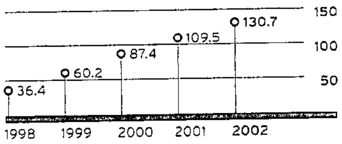
Comment: "The Company's balance sheet is overleveraged"

Response: Although we believe that the Company was not "overleveraged" last year relative to its peers, we know that leverage issues have become more important to the market following recent events in other parts of the energy sector. Our announced strategy to reduce our total debt to $300 million during 2003 has been well received by investors and analysts and should provide us with more financial flexibility in the future.

Comment: "The Company is not on the radar screen for most investors"

Response: During 2002, we substantially increased our efforts to tell our story and improve the knowledge of Denbury in the public markets. We have increased the number of analysts following the Company from three to seven, and beginning last year, we are hosting a semi-annual analysts' technical meeting.

Proved Reserve Growth
In millions of BOEs



Outlook

Future price expectations appear to be moving closer to the mid $20s for oil and the $4.00 range for natural gas, driven by a gradual realization that there are no cheap energy reserves to be found in the United States or overseas. At these price levels, Denbury performs very well, not just based on current cash flow and earnings, but also because additional future projects then become very economical. Denbury is unusual in having already identified a large inventory of projects for both oil and natural gas, requiring estimated capital expenditures of $500 million to $750 million over the next five or so years. Initially in 2003, we plan to reduce debt to $300 million through a combination of asset sales and excess discretionary cash flow. We believe that this conservative policy is prudent, even though commodity prices were high at the start of 2003, as there is a considerable degree of political and economic uncertainty. Once we reach our debt goal, we may somewhat expand our spending as we have a significant inventory of projects. None of these projects are time sensitive and thus will be there when we are ready to pursue them. We look forward to another great year in 2003.

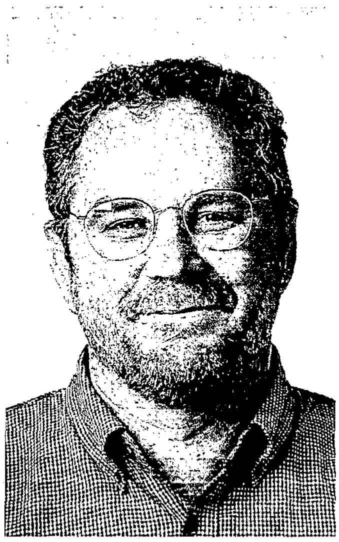


figure 5: Mark Worthey, Senior Vice President of Operations

Gareth Roberts
President and Chief Executive Officer
March 10, 2003

Production Growth
In thousands of BOEs produced per day

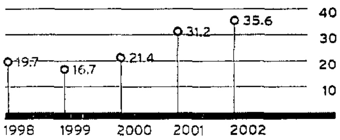


figure 6: Shirley Wheaton, Plano

Oil and Gas Reserves

Estimates of our net proved oil and natural gas reserves as of December 31, 2002, 2001 and 2000 have been prepared by DeGolyer and MacNaughton, independent petroleum engineers located in Dallas, Texas. The reserves were prepared using constant prices and costs in accordance with the guidelines of the Securities and Exchange Commission ("SEC"), based on prices received on a field-by-field basis as of December 31 of each year. The reserves do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties.

Our proved non-producing reserves relate primarily to additional potential from producing zones that are currently behind pipe or are associated with waterfloods and tertiary recovery (CO_2) floods. Since a majority of our properties are in areas with multiple pay zones or are fields with secondary or tertiary recovery operations, most of our properties have both proved producing and proved non-producing reserves.

Reserves associated with our CO_2 operations in West Mississippi and our Heidelberg waterfloods in East Mississippi account for approximately 84% of our proved undeveloped oil reserves. We consider these reserves to be lower risk than proved undeveloped reserves that require drilling at locations offsetting existing production because the reservoir has already been defined by wells that produced during primary production. All of our reserves associated with secondary recovery and tertiary recovery operations are in fields and reservoirs that produced substantial volumes of oil under primary production. The main reason they are classified as undeveloped is because they require significant additional capital to drill wells or install facilities in order to produce the reserves, or they are required to demonstrate a production response after the water or CO_2 is injected before their classification from proved undeveloped can be changed. The remaining 16% of our undeveloped oil reserves are located well within the currently producing regions of our fields, many of which are up-dip to existing production.

Our proved undeveloped natural gas reserves are not as concentrated as our oil reserves. Approximately 62% of our proved undeveloped natural gas reserves are on offshore properties located in six fields, from our latest discovery at North Padre A-9, offshore Texas, to West Delta 27 located offshore eastern Louisiana. These natural gas reserves are confirmed by both sub-surface geology and 3D seismic that covers these areas. An additional 15% of our proved undeveloped natural gas reserves are located in Heidelberg Field where we continue to have success in-fill drilling the Selma Chalk formation. The remaining significant undeveloped natural gas reserves are in our Thornwell/Lakeside and Newark, East (Barnett Shale) areas. In Thornwell/Lakeside our undeveloped reserves are primarily associated with the Bol Perc reservoir where we drilled and completed one additional well during 2002, bringing our total number of successful Bol Perc wells to seven without a dry hole. The Newark, East (Barnett Shale) field is a new and growing area for us. We have now drilled nine wells that have confirmed the presence of commercial gas reserves in this part of the field. We plan to drill an additional six wells during 2003 and assuming gas prices remain strong, we are planning larger development programs in this area in future years. We plan to develop most of our proved undeveloped natural gas reserves during 2003.

figure 7: Charlie Doubek, Plano

		December 31,	
	2002	2001	2000
ESTIMATED PROVED RESERVES:			
Oil (MBbls)	**97,203**	76,490	70,667
Natural gas (MMcf)	**200,947**	198,277	100,550
Oil equivalent (MBOE)	**130,694**	109,536	87,425
PERCENTAGE OF TOTAL MBOE:			
Proved producing	**43%**	53%	57%
Proved non-producing	**23%**	23%	18%
Proved undeveloped	**34%**	24%	25%
REPRESENTATIVE OIL AND NATURAL GAS PRICES: (1)			
Oil – NYMEX	**$ 31.20**	$ 19.84	$ 26.80
Natural gas – NYMEX Henry Hub	**4.79**	2.57	9.78
PRESENT VALUES: (2)			
Discounted estimated future net cash flow before income taxes ("PV10 Value") (thousands)	**$ 1,426,220**	$ 574,328	$ 1,158,969
Standardized measure of discounted estimated future net cash flow after income taxes (thousands)	**1,028,976**	505,795	841,299

(1) The oil prices as of each respective year-end were based on NYMEX prices per Bbl and NYMEX Henry Hub ("NYMEX") prices per MMBtu, with these representative prices adjusted by 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.

figure 8: Jim Johnson, Plano

Field Summaries

Denbury operates in four primary core areas, Louisiana, offshore Gulf of Mexico, Eastern Mississippi and Western Mississippi. Our 15 largest fields constitute approximately 80% of our total proved reserves on a BOE basis and 76% on a PV10 Value basis. Within these 15 fields we own an average 88% working interest and operate all of the 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 three primary field offices in Houma and Covington, Louisiana, and Laurel, Mississippi.

	Proved Reserves as of December 31, 2002 [1]					*2002 Average Production*		
	Oil (MBbls)	*Natural Gas (MMcf)*	*MBOE (000's)*	*BOE % of total*	*PV10 Value ($ 000's)*	*Oil (Bbls/d)*	*Natural Gas (Mcf/d)*	*Average Net Revenue Interest* [2]
Mississippi - CO_2 Floods								
Mallalieu	**10,639**	**-**	**10,639**	**8.1%**	**108,518**	**568**	**-**	**80.9%**
Little Creek	**7,541**	**-**	**7,541**	**5.8%**	**120,883**	**3,393**	**-**	**82.5%**
McComb[3]	**8,293**	**-**	**8,293**	**6.3%**	**53,633**	**1**	**-**	**82.5%**
Other MS - CO_2	**1,397**	**-**	**1,397**	**1.1%**	**18,159**	**8**	**-**	**82.2%**
Total MS - CO_2	**27,870**	**-**	**27,870**	**21.3%**	**301,193**	**3,970**	**-**	**81.9%**
Offshore Gulf of Mexico								
W. Delta 27	**929**	**12,278**	**2,975**	**2.3%**	**49,307**	**350**	**9,132**	**58.9%**
S. Marsh Island 48	**172**	**22,609**	**3,940**	**3.0%**	**67,307**	**65**	**7,379**	**83.3%**
Brazos A-22	**88**	**11,174**	**1,950**	**1.5%**	**21,081**	**11**	**1,695**	**35.7%**
N. Padre A-9	**11**	**10,965**	**1,838**	**1.4%**	**26,067**	**-**	**-**	**41.5%**
Other offshore	**84**	**34,099**	**5,768**	**4.4%**	**107,728**	**177**	**38,027**	**28.0%**
Total offshore	**1,284**	**91,125**	**16,471**	**12.6%**	**271,490**	**603**	**56,233**	**40.9%**
Other Mississippi - Non-CO_2								
Heidelberg	**37,363**	**38,518**	**43,783**	**33.5%**	**327,308**	**6,294**	**7,114**	**78.7%**
Eucutta	**4,978**	**-**	**4,978**	**3.8%**	**46,339**	**1,441**	**31**	**67.8%**
King Bee	**3,536**	**-**	**3,536**	**2.7%**	**26,894**	**694**	**-**	**78.7%**
Brookhaven[3]	**2,086**	**-**	**2,086**	**1.6%**	**28,475**	**172**	**-**	**78.7%**
Laurel[3]	**7,380**	**-**	**7,380**	**5.6%**	**69,450**	**552**	**-**	**73.9%**
Other MS	**10,250**	**2,656**	**10,693**	**8.2%**	**104,865**	**2,828**	**1,237**	**62.2%**
Total Other MS	**65,593**	**41,174**	**72,456**	**55.4%**	**603,331**	**11,981**	**8,382**	**74.5%**
Louisiana								
Lirette	**349**	**13,403**	**2,583**	**2.0%**	**58,572**	**351**	**7,581**	**56.2%**
Thornwell	**595**	**9,865**	**2,239**	**1.7%**	**51,231**	**1,074**	**17,017**	**52.6%**
S. Chauvin	**369**	**10,397**	**2,102**	**1.6%**	**34,482**	**177**	**2,832**	**40.4%**
Other Louisiana	**1,141**	**25,611**	**5,409**	**4.1%**	**93,545**	**599**	**7,664**	**27.8%**
Total Louisiana	**2,454**	**59,276**	**12,333**	**9.4%**	**237,830**	**2,201**	**35,094**	**36.7%**
Other	**2**	**9,372**	**1,564**	**1.3%**	**12,376**	**78**	**734**	**68.9%**
Company Total	**97,203**	**200,947**	**130,694**	**100.0%**	**1,426,220**	**18,833**	**100,443**	**63.0%**

(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, 2002. The prices at that date were a NYMEX oil price of $31.20 per Bbl adjusted by field and a NYMEX natural gas price of $4.79 per MMBtu, also adjusted by field.

(2) Includes only productive wells in which the Company has a working interest as of December 31, 2002.

(3) These fields were acquired during 2002. The average production during the period they were owned by the Company was 515 Bbls/d at Brookhaven and 1,651 Bbls/d at Laurel. Laurel Field was sold in February 2003.

Oil and Gas Acreage

The following table sets forth Denbury's acreage position at December 31, 2002:

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Louisiana	**24,539**	**15,611**	**31,062**	**19,852**
Mississippi	**84,740**	**75,497**	**77,864**	**53,253**
Offshore Gulf Coast	**116,541**	**63,090**	**52,820**	**52,820**
Texas	**3,919**	**3,563**	**19,828**	**16,859**
Total	**229,739**	**157,761**	**181,574**	**142,784**

figure 9: Joni Williams, Plano

Productive Wells

This table sets forth our gross and net productive oil and natural gas wells at December 31, 2002:

	Producing Oil Wells		Producing Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Louisiana	**30**	**12.1**	**55**	**22.4**	**85**	**34.5**
Mississippi	**460**	**350.3**	**76**	**49.9**	**536**	**400.2**
Offshore Gulf Coast	**3**	**1.7**	**76**	**31.0**	**85**	**35.0**
Texas	**–**	**–**	**10**	**7.1**	**10**	**7.1**
Total	**493**	**364.1**	**217**	**110.4**	**716**	**476.8**

Drilling Activity

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

	Years Ended December 31,					
	2002		2001		2000	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells [1]						
Productive [2]	**7**	**3.7**	15	8.2	3	1.1
Nonproductive [3]	**4**	**2.5**	3	1.2	1	0.2
Development wells [1]						
Productive [2]	**33**	**22.7**	60	37.9	38	26.5
Nonproductive [3] [4]	**2**	**1.4**	–	–	2	0.2
Total	**46**	**30.3**	78	47.3	44	28.0

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

(4) During 2002, 2001 and 2000, an additional 9, 24, and 12 wells, respectively, were drilled for water or CO_2 injection purposes.

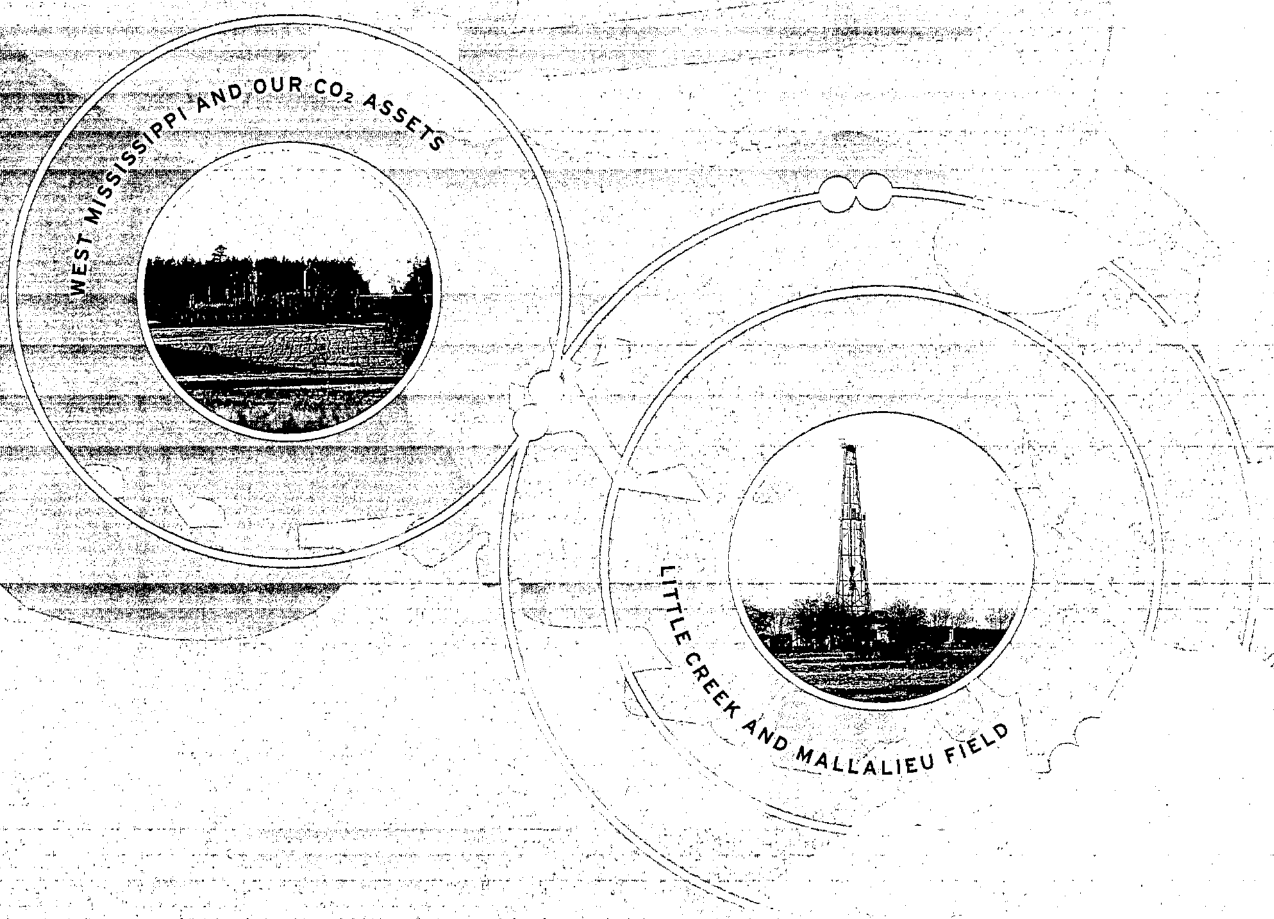


figure 10: **By focusing on our core areas and business plan, we believe that we have assembled a portfolio of**

D Y N A M I C

P R O P E R T I E S.

These properties should provide us with many years of growth.

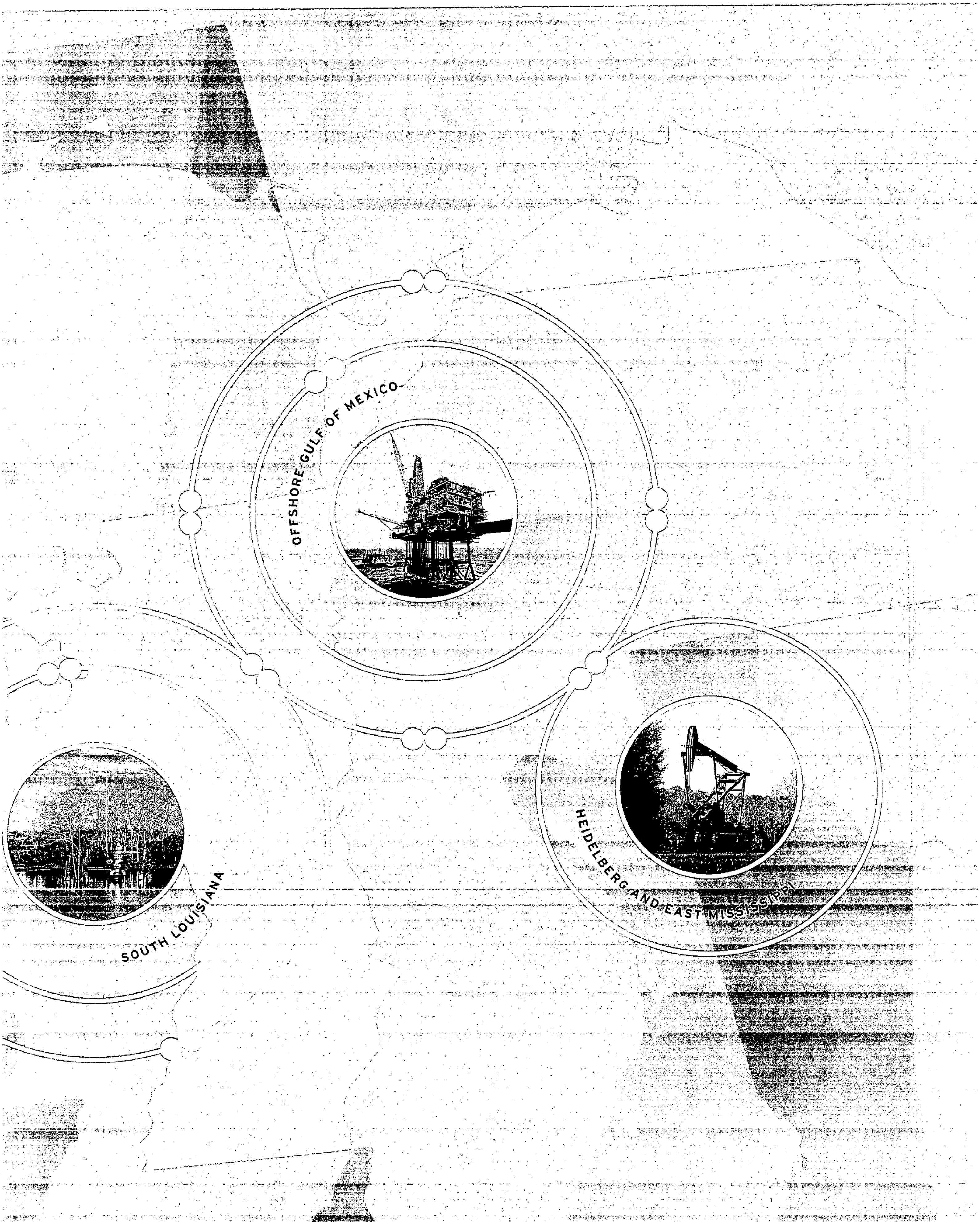

OFFSHORE GULF OF MEXICO
SOUTH LOUISIANA
HEIDELBERG AND EAST MISSISSIPPI

figure 11: Matt Craven, Laurel

WEST MISSISSIPPI AND OUR CO_2 ASSETS

Carbon dioxide ("CO_2") injection is one of the most efficient tertiary recovery mechanisms for producing crude oil; however, its application requires large quantities of CO_2, and therefore its use has been restricted to West Texas, Mississippi and other isolated areas where large quantities of CO_2 are available. The CO_2 acts as a type of solvent for the oil, removing it from the formation and allowing the oil to be recovered along with the CO_2 as it is produced. For example, in a typical oil field, between 40% and 50% of the oil in place can be extracted by primary and secondary (waterflooding) recovery. An additional amount of oil (17% at Little Creek) can be recovered by injecting CO_2 into certain wells and then recovering the additional oil and the CO_2 from other wells.

One of the few natural sources of CO_2 in the United States was discovered around Jackson Dome in Mississippi, a volcanic intrusive, which was emplaced about 80 million years ago. These CO_2 reserves are found in structural traps in the Buckner, Smackover and Norphlet formations at depths of about 16,000 feet. Some estimates have suggested that there are 12 Tcf of usable CO_2 in this area.

In September 1999 we acquired our first CO_2 tertiary recovery project at Little Creek Field in Mississippi, which was 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 3,033 Bbls/d during the fourth quarter of 2002. 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 older 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 two years:

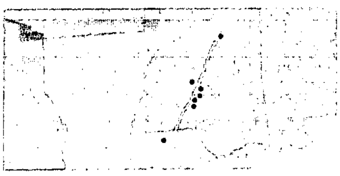


figure 12: Locations of our West Mississippi Jackson Dome assets (and our CO_2 pipeline)

- 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 almost all 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 at a reasonable and predictable cost. Since February 2001, we have acquired an additional CO_2 property and drilled two additional CO_2 wells, increasing our estimated proved CO_2 reserves to approximately 1.6 Tcf as of December 31, 2002. These additional wells are each capable of producing between 20 and 30 MMcf of CO_2 per day. Although the proven and potential reserves are quite large, in order to continue our tertiary development of the old oil fields in the area, incremental production of CO_2 is needed. In order to obtain the additional CO_2 production we plan to drill several additional wells, including one or two more wells during 2003.

- During the fourth quarter of 2002, we sold an average of 63.1 MMcf/d of CO_2 to commercial users and we used an average of 57.4 MMcf/d for our tertiary activities. With the completion of our latest well, currently scheduled for late March 2003, we expect to increase our daily CO_2 production to over 165

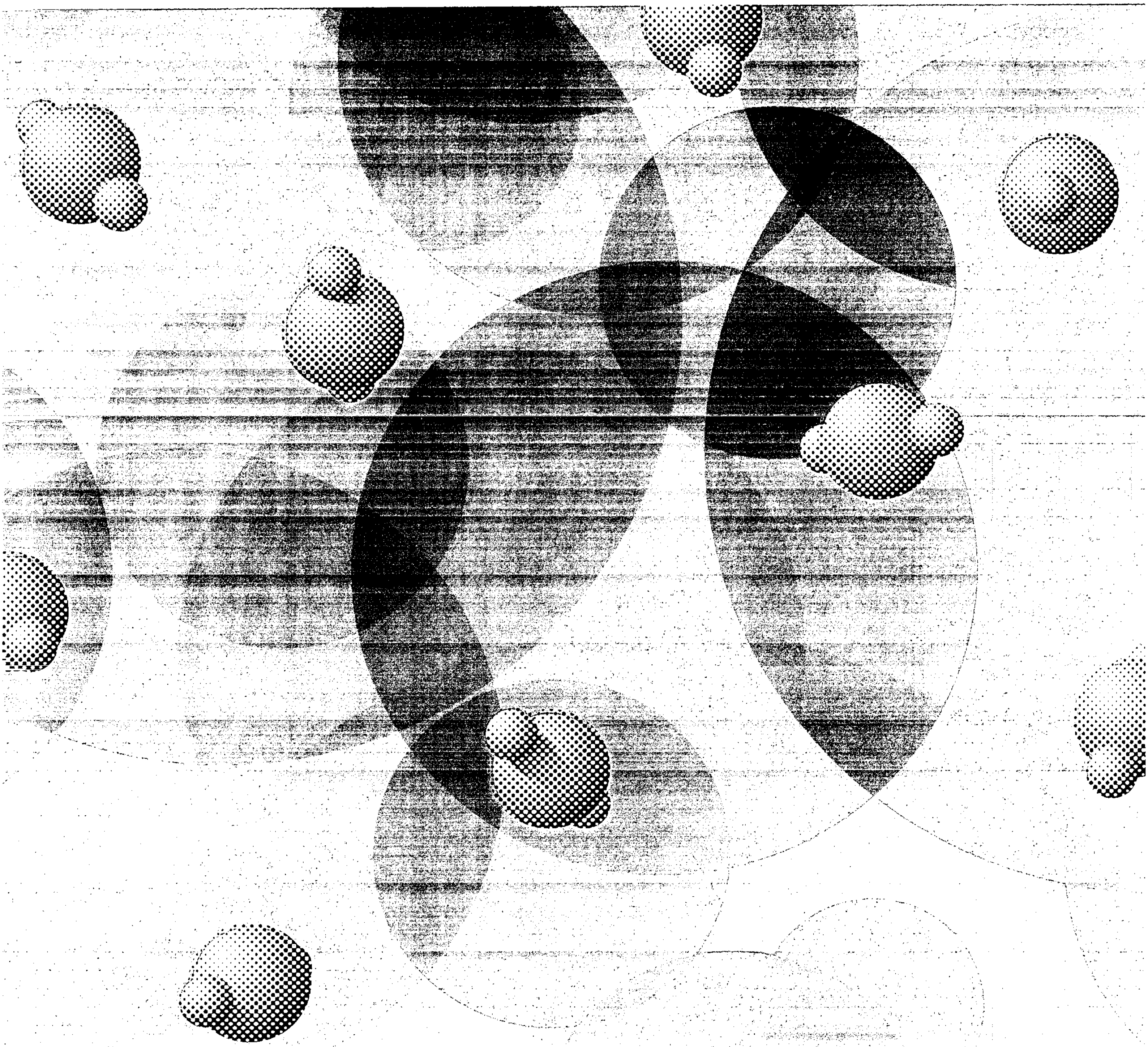


figure 13: **Using CO_2 to increase oil production in depleted fields is one of the innovative**

C H E M I C A L   S O L U T I O N S

that Denbury uses to grow shareholder value.

figure 14: John Ritchie, Little Creek

MMcf/d and by year-end 2003 we hope to further increase our CO_2 production to approximately 200 MMcf/d. We expect to continue our CO_2 drilling in 2004 and beyond, with plans to increase the CO_2 production to over 300 MMcf/d within the next couple of years. We expect the majority of the incremental production to be used in our tertiary recovery operations, while we expect CO_2 sales to industrial customers to continue to provide us with net cash flow of around $6 to $7 million per year for the next several years. As of December 31, 2002, the present value of these industrial contracts discounted at 10% per year was approximately $57 million based on the current life of each contract. We believe the majority of these contracts will be extended beyond their current terms, which would result in the present value of the industrial sales being higher.

- 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 fields in this area, the acquisition cost of both of these fields was relatively low in comparison to the significant reserve potential as a tertiary recovery project. As an example, we acquired West Mallalieu 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. We expect the development cost at these fields to average around $4.00 per BOE.

- In August 2002, we acquired COHO Energy Inc.'s Gulf Coast properties for $48.2 million, which as of year-end 2002 contained an estimated 15.0 million barrels of oil (excluding any potential reserves from tertiary recovery). Brookhaven Field, another significant tertiary flood candidate along our CO_2 pipeline, was included in the properties acquired from COHO. By exploiting our scale, regional competitive advantage and strategic ownership of the general partner interest in Genesis Energy, we were able to increase the average realized price for post-acquisition production from these properties by approximately $3.40 per barrel (relative to NYMEX prices) over the prices that COHO realized earlier in 2002. This translates into a 50% increase in the PV-10 Value of the acquisition, using constant prices and the future price strip as of the time of acquisition. We do not expect to begin development of Brookhaven Field until at least 2004, but believe that this field contains one of the area's most significant opportunities for potential oil reserves using CO_2 tertiary recovery. In February 2003, we sold one of the acquired COHO fields, Laurel Field, for $27.0 million and also received an interest in another field and seismic data valued by us at approximately $1.0 million. At December 31, 2002, Laurel Field had 7.4 MMBbls of proven reserves, just less than 50% of the total proved reserves of the COHO properties acquired in August 2002.

- In May 2002, we acquired the 2.0% general partner interest in Genesis Energy, L.P. Genesis is engaged in crude oil gathering, marketing and transportation with three primary pipeline systems in Texas, Alabama/Florida and Mississippi. Genesis' Mississippi pipeline runs near several of our tertiary recovery operations in southwest Mississippi and within 25 miles of our Heidelberg Field and several of our other east Mississippi fields. This acquisition has enhanced our marketing position for our Mississippi oil production. Genesis could also function as a financier and operator of new pipelines and gathering systems that are required in order to develop these fields.

With anticipated all-in finding and development costs of approximately $4.00 per BOE and anticipated operating costs of $9.00 to $10.00 per BOE over the life of each field, these tertiary recovery operations in West Mississippi along our pipeline should prove to be highly profitable, even at $18 to $20 oil prices, as they produce light sweet oil that receives near NYMEX pricing. We believe there is also significant potential in the future to extend our pipeline to eastern Mississippi and/or southern Louisiana to exploit the use of CO_2 in tertiary recovery operations in these areas.

The western part of Mississippi has produced over 245 MMBbls of light sweet crude oil from Tuscaloosa sandstones at a depth of about 10,000 feet. The application of a theoretical recovery factor of 17% of original oil in place suggests that about 80-100 MMBbls of additional gross reserves may be available in fields in this part of the state. To date, we have booked approximately 38.2 MMBOE (gross) of this potential as proven reserves, of which 4.1 MMBbls (gross) has been produced to date. Obviously, a great deal of work is required before these additional reserves can be recorded as proved reserves, such as additional landwork, reworking/reentering wells and installing production facilities. We plan to spend around $43.0 million in this area during 2003, the largest single portion of our $130 million 2003 exploration and development budget.

figure 15: Kim Lendemann, Covington

LITTLE CREEK, MALLALIEU AND McCOMB 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, these first two phases were substantially complete and Phase III was in process. We have completed Phase III and Phase IV and have initiated Phase V utilizing CO_2 injection. Our plans in 2003 are to continue the development of these phases. Currently there are 39 producing wells and 26 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 that portion of the field by approximately 17%, as compared to approximately 20% for primary recovery and 18% for secondary recovery. The field has produced a cumulative 61.9 gross MMBbls of light sweet crude and we currently estimate that an additional 9.1 gross MMBbls can be recovered.

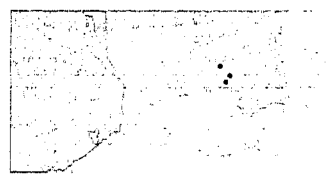


figure 16: Locations of our Little Creek, Mallalieu and McComb assets

Production from Little Creek Field was approximately 1,350 Bbls/d when we acquired it in 1999. During the fourth quarter of 2002, production had increased to an average of 3,033 BOE/d. With our recent increases in CO_2 production, we expect the production from Little Creek to increase further during 2003 by another 750 to 1,250 BOE/d.

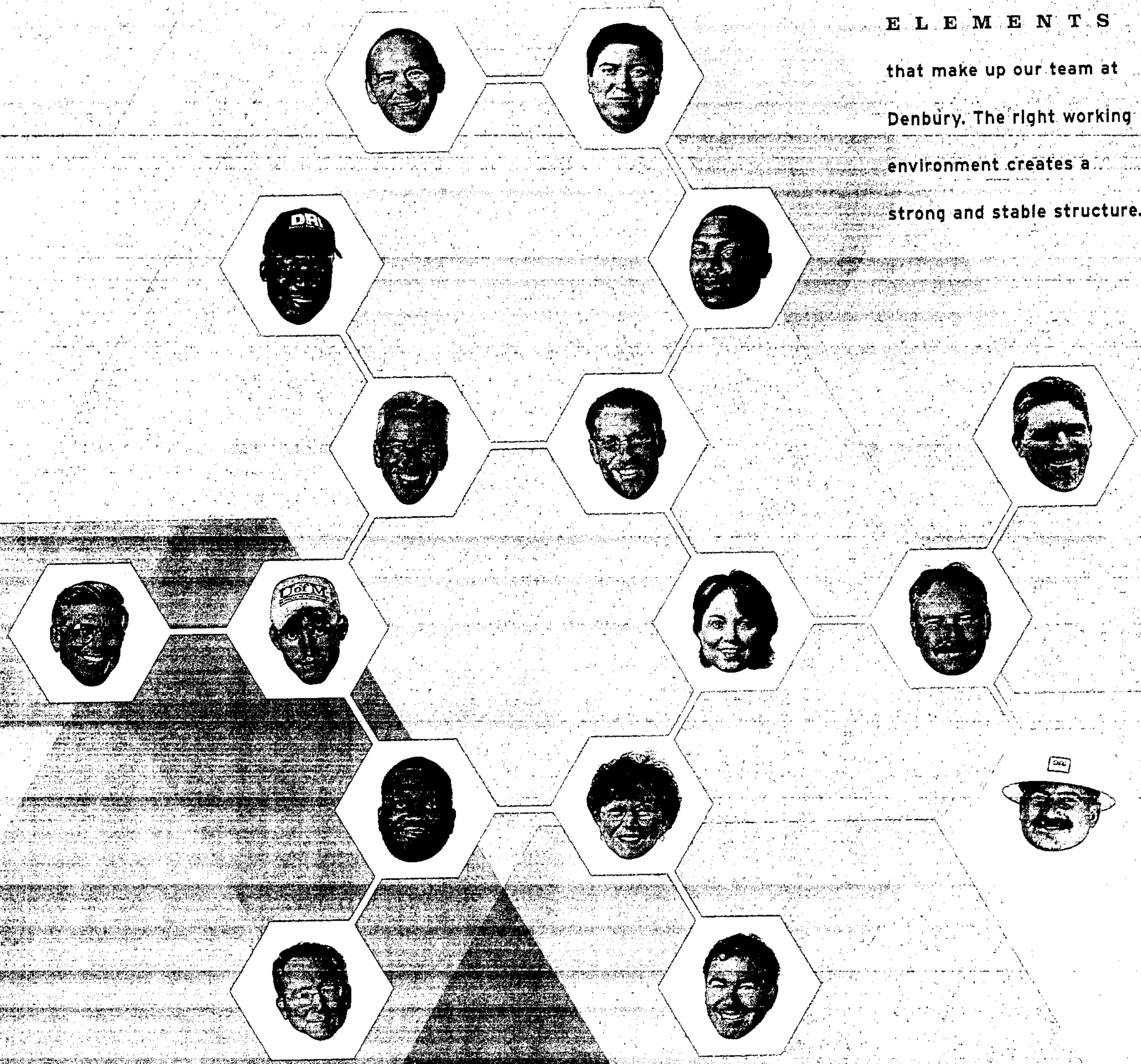


figure 17:
Skilled employees are the **ESSENTIAL ELEMENTS** that make up our team at Denbury. The right working environment creates a strong and stable structure.

In addition to our expansion activities at Little Creek, we purchased West Mallalieu Field in May 2001. West Mallalieu Field was originally unitized by Shell Oil Company, and a subsequent pilot project was commenced in 1986. The pilot project, consisting of four 5-spot patterns, has cumulatively produced approximately 2.3 MMBbls of oil as a result of CO_2 flooding. We expanded the pilot project by adding an additional four patterns during 2001 and an additional four patterns in 2002. During 2002 we began to see initial response to CO_2 injection as the unit averaged 778 Bbls/d during the fourth quarter of 2002. In contrast to Little Creek Field, West Mallalieu Field was not waterflooded prior to CO_2 injection. Therefore, the tertiary recovery of oil from West Mallalieu Field Unit as a result of CO_2 injection could exceed the 17% of original oil in place that we expect from Little Creek Field.

figure 18: *Louis Billiot, Houma*

McComb Field, purchased in 2002, has not had any pilot programs or tertiary operations to date and has virtually no current oil production, but is close in proximity and analogous to our fields at Little Creek and Mallalieu. We plan to commence tertiary recovery operations in 2003 and expect to see initial oil production responses in early 2004. As of December 31, 2002, we had recognized 8.3 MMBOE of proven reserves at McComb Field. The total potential from McComb Field is estimated to be as much as twice the booked proven reserves and thus we expect the reserves at McComb to increase over the next several years as we develop the field in its entirety.

At December 31, 2002, we had proved reserves of 27.9 MMBOE relating to our tertiary recovery operations. Through December 31, 2002, we had spent a total of $74.4 million on fields in this area, primarily Little Creek and Mallalieu Fields, and have received $50.1 million in net operating income, leaving us a balance of $24.3 million to recover for payout. This compares to a PV-10 Value, using December 31, 2002 SEC pricing of $31.20 per Bbl, of $301.2 million for the proved reserves in these fields.

OFFSHORE GULF OF MEXICO

Denbury's second largest focus area for 2003 is the federal offshore waters of the Gulf of Mexico. Employing the latest 3D seismic techniques and interpretations has allowed us to better understand the complexities of these offshore areas. Denbury owns an interest in 85 wells and operates 68 of these wells (80%) from its regional office in Covington, Louisiana. Based on our initial successful results in the Gulf of Mexico, in July 2001 we purchased Matrix Oil & Gas, Inc. Matrix had followed our same strategy of acquiring offshore fields from the major oil and gas companies that had produced large quantities of oil and natural gas. We believe large fields that have produced hundreds of millions of barrels of oil and hundreds of billions of cubic feet of natural gas generally have an additional 10% to 15% of additional reserves which can be produced when detailed geology and engineering work is applied. The Matrix properties were producing approximately 40 MMcf/d at the time of the acquisition.

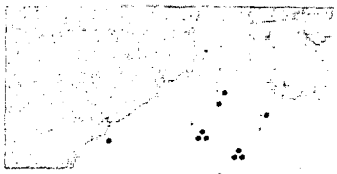


figure 19: *Locations of our offshore Gulf of Mexico assets*

Due to the downturn in natural gas prices that occurred late in 2001, we budgeted little drilling activity offshore during 2002, with planned spending limited to workovers, recompletions and other maintenance

figure 20: Fred Mahaffey, Little Creek

type projects. We drilled only two offshore wells late in the year, both successful exploration wells at North Padre Island A-9. Our total spending during 2002 was approximately $17.1 million in this region, approximately 15% of our total exploration and development budget. During 2002 there were two storms in the Gulf of Mexico, Tropical Storm Isidore and Hurricane Lili, which impacted our offshore production and caused significant damage to one of our offshore platforms. Most of this damage was covered by insurance, but we did expense approximately $750,000 during the fourth quarter of 2002 related to the insurance deductibles and certain items not covered by insurance. Even with the reduced spending and the losses in production caused by the two storms, our production offshore averaged 59.9 MMcfe/d during 2002, slightly higher than the 2001 average of approximately 55 MMcfe/d during the period they were owned by us. During 2003, our offshore spending will be significantly higher, primarily due to several prospects we developed during 2002 and intend to drill in 2003. We expect to spend an estimated $41.0 million on offshore activities, or 32% of our $130.0 million 2003 exploration and development budget.

We booked net proved reserves as of year-end 2002 of approximately 11 Bcf net to our interest in the two wells at North Padre Island A-9 drilled in late 2002. This discovery should be on production in the second half of 2003.

During 2003 we expect to drill eight to ten wells, with unrisked potential target objectives ranging from 5 Bcf to 55 Bcf, net to our interest. These plays are supported with 3D seismic that is enhanced by modern acquisition techniques, the latest processing techniques and seismic modeling. The application of these techniques allows our geoscientists to better image deeper reservoirs and recognize hydrocarbon indicators in and around these mature prolific fields. Our scheduled wells include both development and exploration prospects at Brazos A-21 and A-22, High Island A-6, West Cameron 192, East Cameron 33, West Cameron 427 and West Delta 27.

SOUTH LOUISIANA

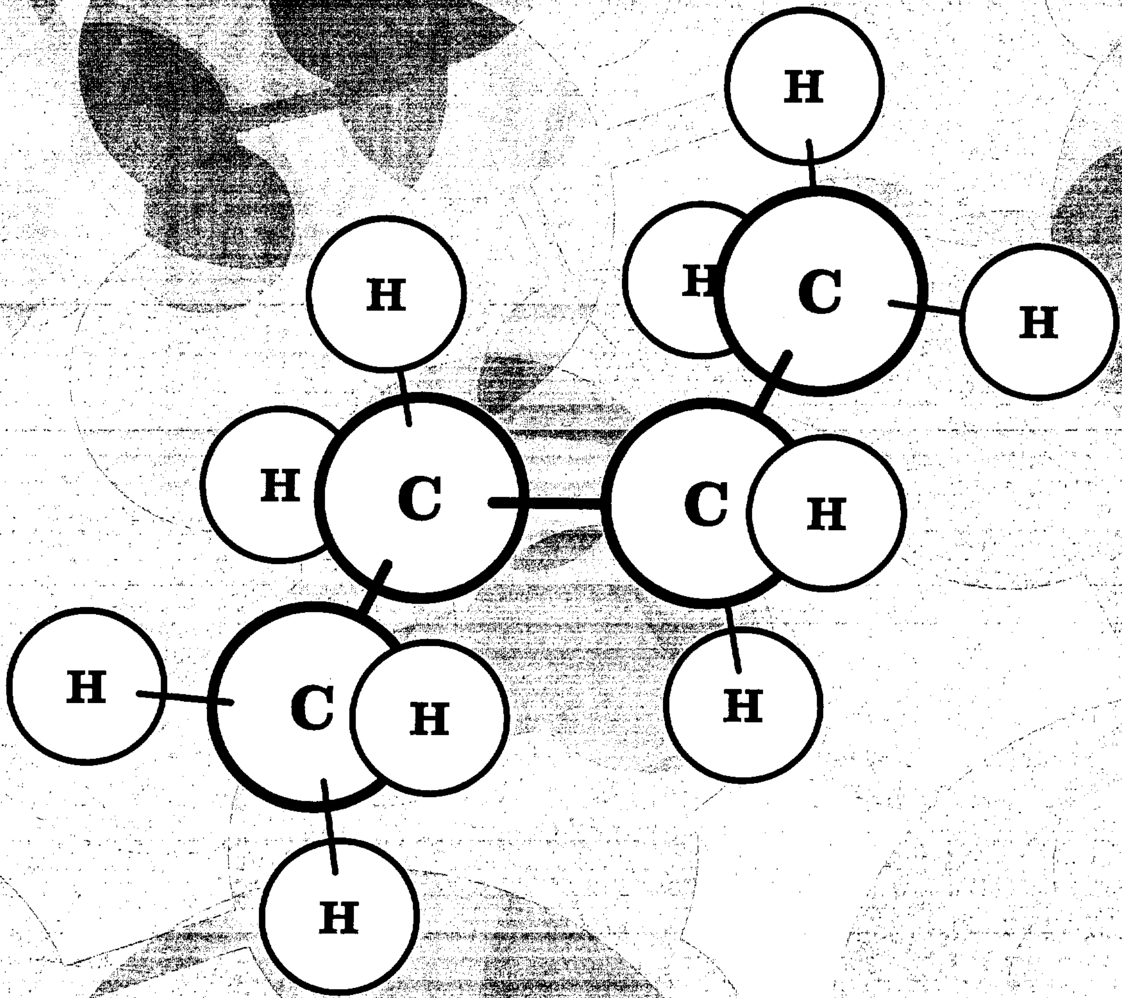
Denbury operates on the land and in the marshes of South Louisiana, including state waters. We own interests in 85 wells and operate 63 of these wells (74%) from our regional office in Houma, Louisiana. This region produces primarily natural gas, averaging 34.4 MMcf/d net to our interest in the fourth quarter of 2002, approximately 38% of our total natural gas production. During 2002, we spent approximately $35.0 million in this region, approximately 32% of our total exploration and development budget, drilling approximately 10 wells, primarily in the Thornwell and Terrebonne Parish areas (Lirette, Bay Baptiste, Bayou Rambio and Lake Gero). For 2003, our spending will be reduced somewhat in this area to an estimated $21.0 million, or 16% of our $130.0 million exploration and development budget, as we focus more of our natural gas exploration and development efforts in the offshore Gulf of Mexico.

figure 21: Locations of our assets in southern Louisina

The majority of our onshore Louisiana fields lie in the Houma embayment area of Terrebonne Parish, including Lirette, Bayou Rambio and South Chauvin Fields, and a recent shallow natural gas play at *figure 22:* At Denbury we produce roughly equal volumes of oil and natural gas which creates an

ORGANIC CHEMISTRY

between the price fluctuations of each commodity.



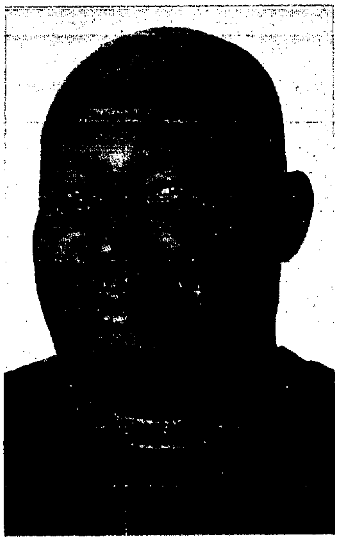


figure 23: George Peebles, Eucutta

Lake Gero. The advent of 3D 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 630 square miles of 3D data, and plan to expand our data ownership. During 2002, we expanded our seismic holdings in this area by acquiring an additional 290 square miles of 3D data. We drilled six wells in Terrebonne Parish during 2002, four of which were discoveries. In 2003, we plan to drill around 15 wells, eight of which are planned to further exploit the shallow gas play in the Lake Gero area, five of which we expect to drill in the Thornwell area, primarily targeting additional Bol Perc potential, and the rest of which we expect to be drilled at other fields in the Terrebonne Parish area using similar 3D interpretation techniques.

Our activities in the Lake Gero area of Terrebonne Parish provided strong results during 2002. We re-processed a portion of our Terrebonne seismic to better image the shallower sands in the area. The majority of newer data being shot is to image the deeper sands, thus the processing of the shallow sands has generally been overlooked. This reprocessing indicated there were multiple shallow seismic anomalies present in the area around Lake Gero. We drilled two successful wells at Lake Gero during the year. These reservoirs are shallow, approximately 3,000 feet deep, but the two wells produced an average of 4,000 Mcf/d during the fourth quarter of 2002. We plan to drill an additional eight wells in the Lake Gero area during 2003. In addition to the Lake Gero area, through our seismic reprocessing, we have another 12 prospects in the Terrebonne Parish area we are currently reviewing.

We were very active in the Thornwell Field area, located in Cameron and Jeff Davis Parishes, during 2001 and 2002. This field, purchased in late 2000, produced an average of 23.5 MMcfe/d net to our interest during 2002. Our primary interest in purchasing this field was the substantial upside potential that we believe exists in the continued development of the existing producing zones (Bol Perc), and the exploration potential of several deeper zones (Marg Howei and Camerina). All of these prospects were defined by a 110 square mile 3D seismic survey. During 2002 we continued successful development of the Bol Perc sands, with the drilling of one Bol Perc well. During 2002, we also drilled the Lacassane #6-1 (Brenda prospect), which targeted the Camerina formation. We were unsuccessful in our largest target, the Lower Camerina sands, although this well did prove up additional Bol Perc prospects in another fault block and reserves in the shallower Camerina sands. The Lacassane #6-1 produced an average of 3.5 net MMcfe/d during the fourth quarter of 2002. In addition to drilling these two wells, during 2002 we expanded our acreage position over several Bol Perc anomalies, recompleted a well that averaged 2.8 MMcfe/d and purchased one additional well. During 2003, we plan to drill four additional Bol Perc wells and one Marg Howei well, although our total spending in this area, budgeted at approximately $7.0 million, will be less than the $18.8 million spent here in 2002.

HEIDELBERG AND EAST MISSISSIPPI

In the eastern part of the Mississippi salt basin, from our office in Laurel, Mississippi, we operate 418 wells (91%) out of 459 in which we own an interest. These fields produced an average of 14,165 Bbls/d and 9.2 MMcf/d during the fourth quarter of 2002. The largest field in the region, and our largest field is Heidelberg Field, which for the fourth quarter of 2002 produced an average of 7,290 BOE/d. 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. In general, we have owned our Eastern Mississippi properties longer than properties in most of our other regions and thus they are more fully developed and we are spending less in this region than in our other three regions. During 2002, we drilled 28 wells and performed various workovers, recompletions and other maintenance type projects, with total spending (excluding acquisitions) during 2002 of approximately $24.0 million in this region, approximately 21% of our total exploration and development budget. As a result of our reduced spending here during the year, our production in Eastern Mississippi averaged 13,379 BOE/d during 2002, just slightly less than the 2001 average of 13,481 BOE/d. For 2003, our spending will be about the same as in 2002, as we expect to spend an estimated $21.0 million, or 16% of our $130.0 million 2003 exploration and development budget in this region.

figure 24: Jeff Marcel, Houma

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, recompletions, improvements in production efficiency, and in some cases, by water flooding producing reservoirs. Most of our wells produce large amounts of saltwater and require large pumps, which increases 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 eventually CO_2 flooding (tertiary recovery). Future tertiary recovery operations may offer the biggest upside potential in this area. Although the reserve potential here is significant, we are initially developing the fields along our CO_2 pipeline (see "West Mississippi and our CO_2 Assets" above), as the CO_2 is easily delivered to these fields, which produce light sweet oil that commands a higher price (relative to NYMEX) than the production from the Eastern Mississippi properties. To extend our tertiary CO_2 operations to Eastern Mississippi will require a pipeline and slightly higher oil prices for this production than production from our Western Mississippi properties. The higher oil price is needed to provide similar rates of return, due to the overall quality of the crude oil and a higher negative differential to NYMEX prices, and in order to cover the additional cost of building a pipeline. However, with the high oil prices prevailing in late 2002 and early 2003, tertiary operations appear to be profitable. We plan to further evaluate this potential during the next couple of years, as this could be part of our future expansion plans.

Our primary interests at Heidelberg Field, our single largest field, were acquired from Chevron in December 1997. This field was discovered in 1944 and has produced an estimated 196 MMBbls of oil and 39 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, production was approximately 2,800 BOE/d. As a result of our subsequent development work, production for 2002 averaged 7,479 BOE/d.

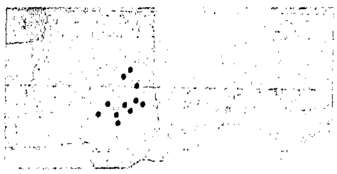


figure 25: Locations of our Heidelberg and other Eastern Mississippi assets

figure 26: James Thomas, Heidelberg

The primary oil production at Heidelberg is from five waterflood units that produce from the Eutaw formation (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 single 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 wells here in 2001 and 13 in 2002 that effectively reduced the well spacing to 40 acres in East Heidelberg, and increased the natural gas production at Heidelberg to an average for the year of around 7.1 MMcf/d and a fourth quarter average of 7.9 MMcf/d. We believe that there may be opportunities to further reduce the well spacing and we plan to drill an additional 11 Selma Chalk wells in 2003.

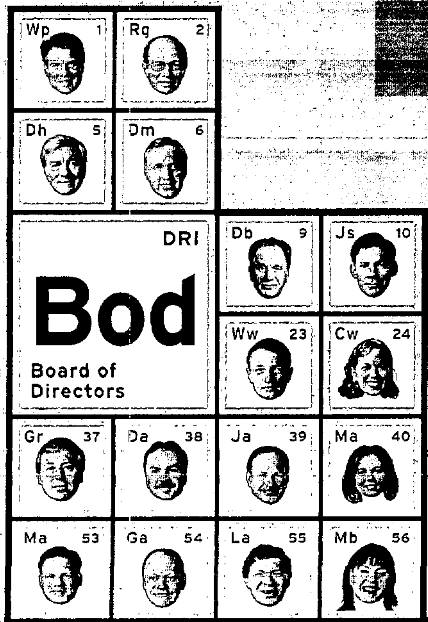
We have pursued the same strategy at our other significant fields in East Mississippi: Eucutta, Quitman, Davis, Sandersville and King Bee Fields. After we acquired each of these oil fields, we initiated a rework program to increase production and reserves. We shot the first 3D seismic survey ever shot over King Bee Field (Cypress Creek Dome) in 2001, a field we acquired from Fina in 1999. King Bee Field is a salt dome with relatively few wells drilled over the years because it underlies a national forest and a U.S. military bombing range. Due to these surface restrictions, wells have to be drilled from sites outside of the bombing area, and thus well costs are higher than normal. The higher costs of drilling and the steeply dipping beds of the producing formations make it imperative to have a very good geologic picture of the subsurface to minimize the risks prior to drilling. We drilled our first well at King Bee during 2002, which we plan to convert to an injection well during the second quarter to begin a pressure maintenance project in the largest reservoir currently in the field. Based on our simulation study, we believe this project will allow us to recover a significant amount of additional oil reserves (up to 1.0 MMBbls) that would not be recovered otherwise. During 2003, we also plan to drill our first well based on the 3D seismic data we shot over the field. This seismic data has revealed a very complex and highly faulted field that will require extremely detailed subsurface geology and geophysical efforts. We have identified an additional four to six prospect leads at this time.

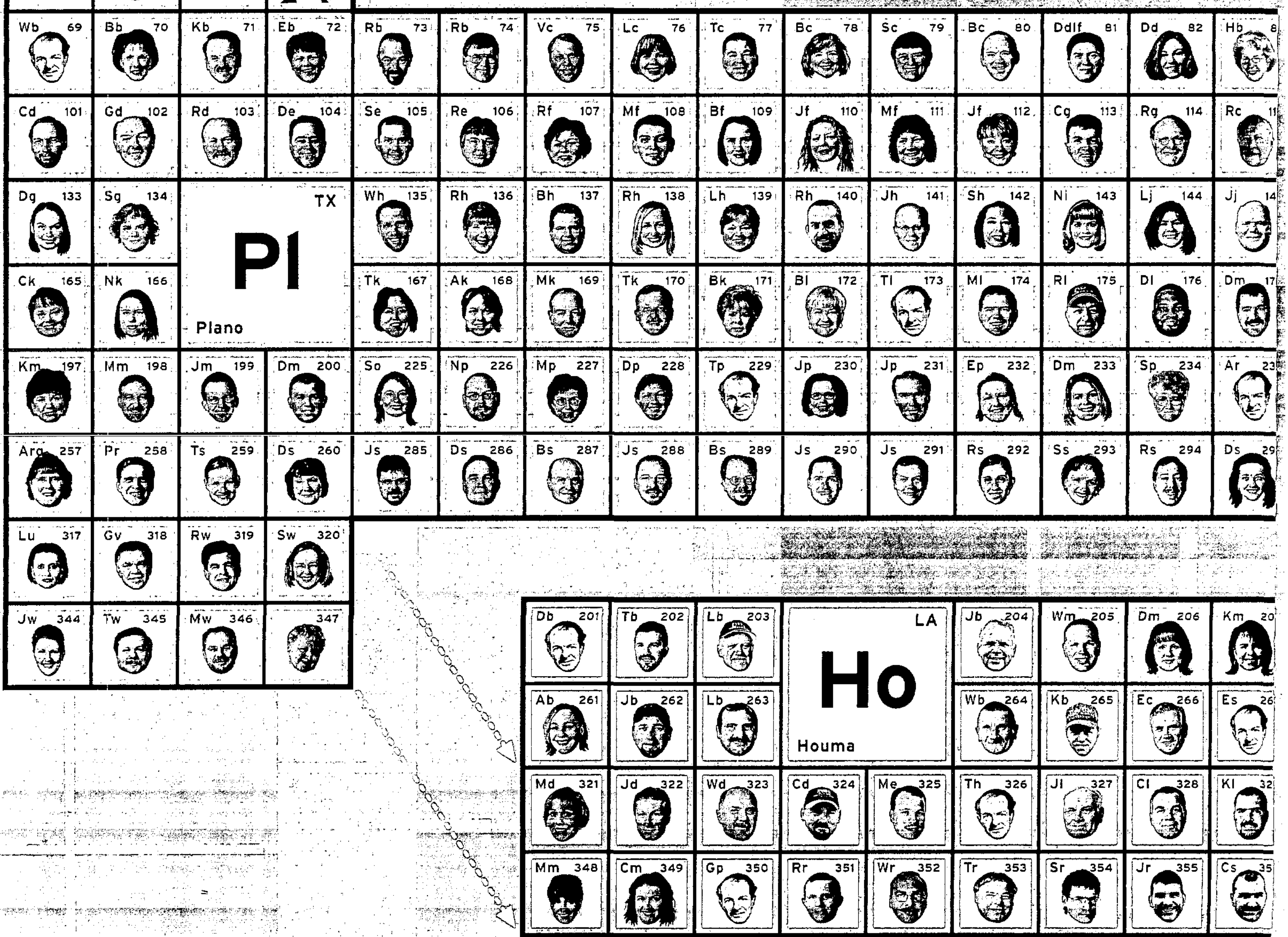
BARNETT SHALE

Denbury also owns about 22,000 acres of leases in the Fort Worth Basin that is prospective for the Barnett Shale. Six wells were drilled in 2001 and two in 2002, all but one of which were producing as of year-end 2002. Due to low natural gas prices in late 2001, our 2002 development of this area was limited, as we spent only approximately $2.2 million there during 2002. Although we believe this area has a reserve potential in excess of 200 Bcf, it requires natural gas prices greater than $3.00 per Mcf in order to provide us with our minimum acceptable rate of return. As such, our other areas have provided better opportunities to date. We have entered into two joint ventures with business partners to drill up to 60 wells in this area. The addition of these wells, combined with the nine wells we have drilled, will prove up the majority of our acreage, leaving us the opportunity to further exploit this area in 2004 and beyond.

DENBURY PERIODIC TABLE OF THE ELEMENTS

1	William S. Price, III	Board of Directors	38	Dale Adams	Plano
2	Ronald G. Greene	Board of Directors	39	James Adams	Plano
3	Druscilla Allen	Laurel	40	Melinda Adams	Plano
4	Kerry Allen	Laurel	41	Freddie Bessonette	Little Creek
5	David I. Heather	Board of Directors	42	Bernard Boothe	Little Creek
6	David B. Miller	Board of Directors	43	Matt Craven	Laurel
7	Johnny Barr	Laurel	44	John Crosby	Laurel
8	Bob Bush	Laurel	45	George Davis, II	Laurel
9	David Bonderman	Board of Directors	46	Larry Eidson	Laurel
10	Jeffrey Smith	Board of Directors	47	David English	Laurel
11	Brandon Scott Allen	Little Creek	48	Ricky English	Laurel
12	Daniel Allen	Little Creek	49	Ricky Fields	Laurel
13	Ronnie Giles	Little Creek	50	Ronnie Fontenot	Laurel
14	Robert Ayers	Little Creek	51	Timothy Gatlin	Laurel
15	Clifford Britt	Little Creek	52	Teddy Golobay	Laurel
16	Billy Joe Beal	Laurel	53	Mark Allen	Plano
17	Jody Blackledge	Laurel	54	Greg Andersen	Plano
18	Bradley Boothe	Laurel	55	Lonnie Ashley	Plano
19	Ronnie Brewer	Laurel	56	Martha Balogh	Plano
20	Robert Barrett	Laurel	57	Betty Boothe	Little Creek
21	David Brown	Laurel	58	Jared Boothe	Little Creek
22	Doug Brown	Laurel	59	Michael Bostic	Little Creek
23	Wieland F. Wettstein	Board of Directors	60	Caesar Hales	Laurel
24	Carrie A. Wheeler	Board of Directors	61	Ray Harris	Laurel
25	Lisa Ballard	Little Creek	62	Terry Hayes	Laurel
26	Toby Ballard	Little Creek	63	James Hendry	Laurel
27	Alice Baily	Little Creek	64	Jared Dant Hendry	Laurel
28	Lester Butler	Laurel	65	Melinda Hendry	Laurel
29	Clarence W. Carter	Laurel	66	Jamie Hickson	Laurel
30	Rowan Carter	Laurel	67	Michael Hickson	Laurel
31	Paul Chisholm	Laurel	68	Brad Hobson	Laurel
32	Sam Clements	Laurel	69	William Barber	Plano
33	James Cochran	Laurel	70	Brenda Borden	Plano
34	Steven Cochran	Laurel	71	Keith Bowman	Plano
35	Johnny Collier	Laurel	72	Elba Brown	Plano
36	David Craven	Laurel	73	Rock Brown	Plano
37	*Gareth Roberts*	*Board of Directors*	74	*Randy Burrow*	*Plano*
		Plano	75	Vincent Cangemi	Plano





76	Leslie Carter	Plano
77	Tom Cassard	Plano
78	Bonnie Colgin	Plano
79	Sandra Courville	Plano
80	Bradley Cox	Plano
81	David de la Fuente	Plano
82	Danielle Donahue	Plano
83	Hulene Breland	Brandon
84	Dalton Case	Brandon
85	William Bryan	Little Creek
86	Adam Burke	Little Creek
87	Corey Case	Little Creek
88	Derick Case	Little Creek
89	Howard Denson Case	Little Creek
90	Vernon Case	Little Creek
91	Thomas Cole	Little Creek
92	Clifton Connelly	Little Creek
93	Lewis Cornell	Little Creek
94	Jack Hobson	Laurel
95	Lynell Howard	Laurel
96	Jeffrey Hudson	Laurel
97	Albert Jackson	Laurel
98	Ben James	Laurel
99	Heather Jenkins	Laurel
100	Scottie Johnson	Laurel
101	Charlie Doubek	Plano
102	Greg Dover	Plano
103	Raymond Dubuisson	Plano
104	Dean Edzards	Plano
105	Steve Emerson	Plano
106	Ronald Tracy Evans	Plano
107	Rhonda Farrow	Plano
108	Michael Fiorito	Plano
109	Brandi Firtos	Plano
110	Janet Freeman	Plano
111	Mary Fritsch	Plano
112	Janet Fry	Plano
113	Charles Gibson	Plano
114	Ronald Gramling	Plano
115	Russell Champlin	Brandon
116	Arnold Jackson	Brandon
117	Dallas Lance Daley	Little Creek
118	William Davis	Little Creek
119	William Duncan	Little Creek
120	Kevin Edwards	Little Creek
121	Robert Fauver	Little Creek
122	Donald Ferguson	Little Creek
123	Richard Gayle	Little Creek
125	Edward Johnston	Little Creek
126	Kevin Kellum	Laurel
127	Joseph Lindsey	Laurel
128	Stephen Little	Laurel
129	Carl R. Lofton	Laurel
130	Darrell Lofton	Laurel
131	Thomas Lofton	Laurel
132	Robert Madison, Jr.	Laurel
133	Destine Greenwood	Plano
134	Shelley Guilliams	Plano
135	Wayne Haley	Plano
136	Rita Harden	Plano
137	Brandon Harris	Plano
138	Rebecca Hollfield	Plano
139	Linda Holmes	Plano
140	Randall Holt	Plano
141	James Howard	Plano
142	Susan Hux	Plano
143	Nancy Iske	Plano
144	Lorci Jackson	Plano
145	James Johnson	Plano
146	Carolyn Jones	Plano
147	Allison Keefer	Plano
148	Frank Jones	Little Creek
149	Bruce King	Little Creek
150	Edward King	Little Creek
151	Ernest Kinkaid	Little Creek
152	Fred Manaffey	Little Creek

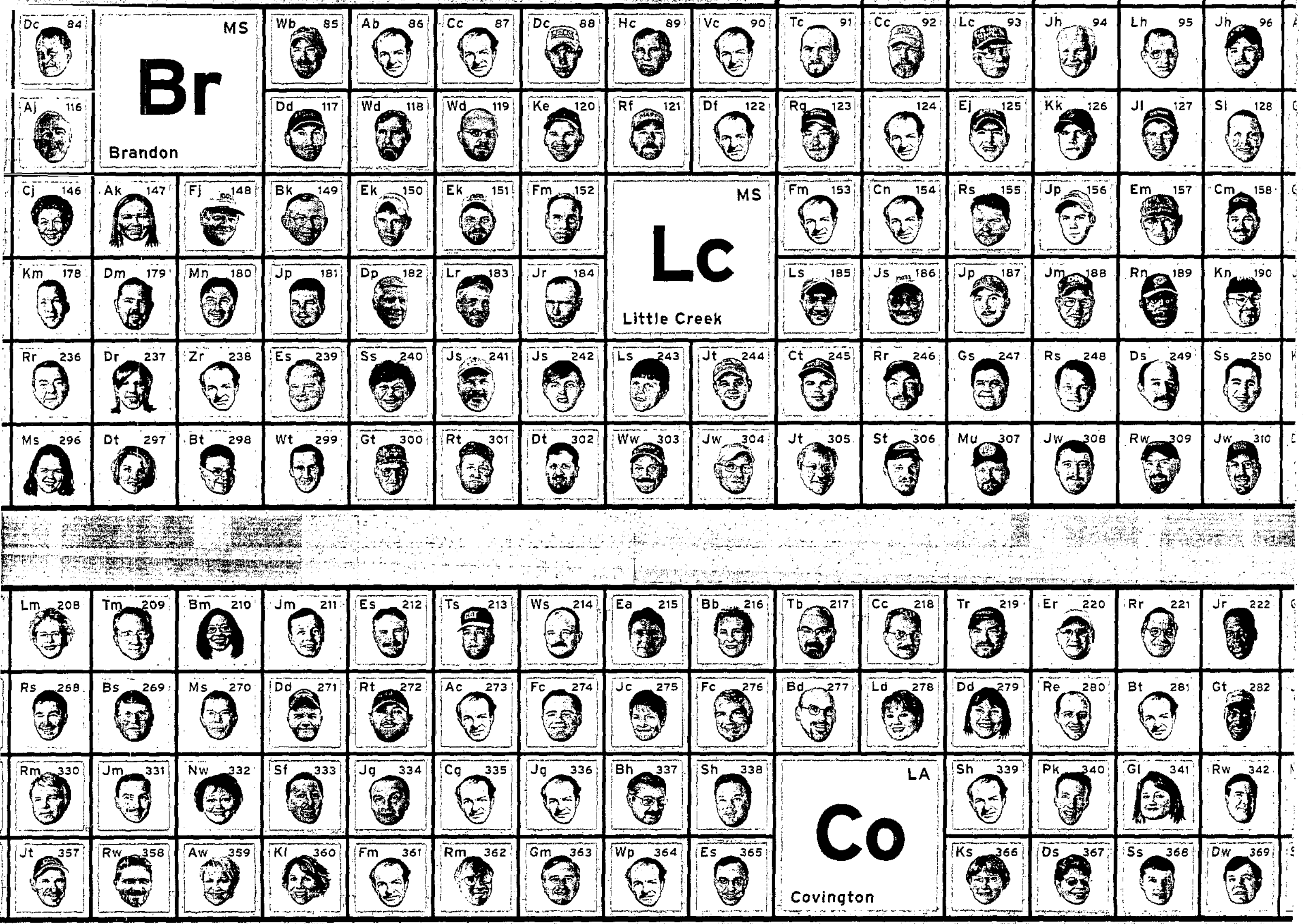
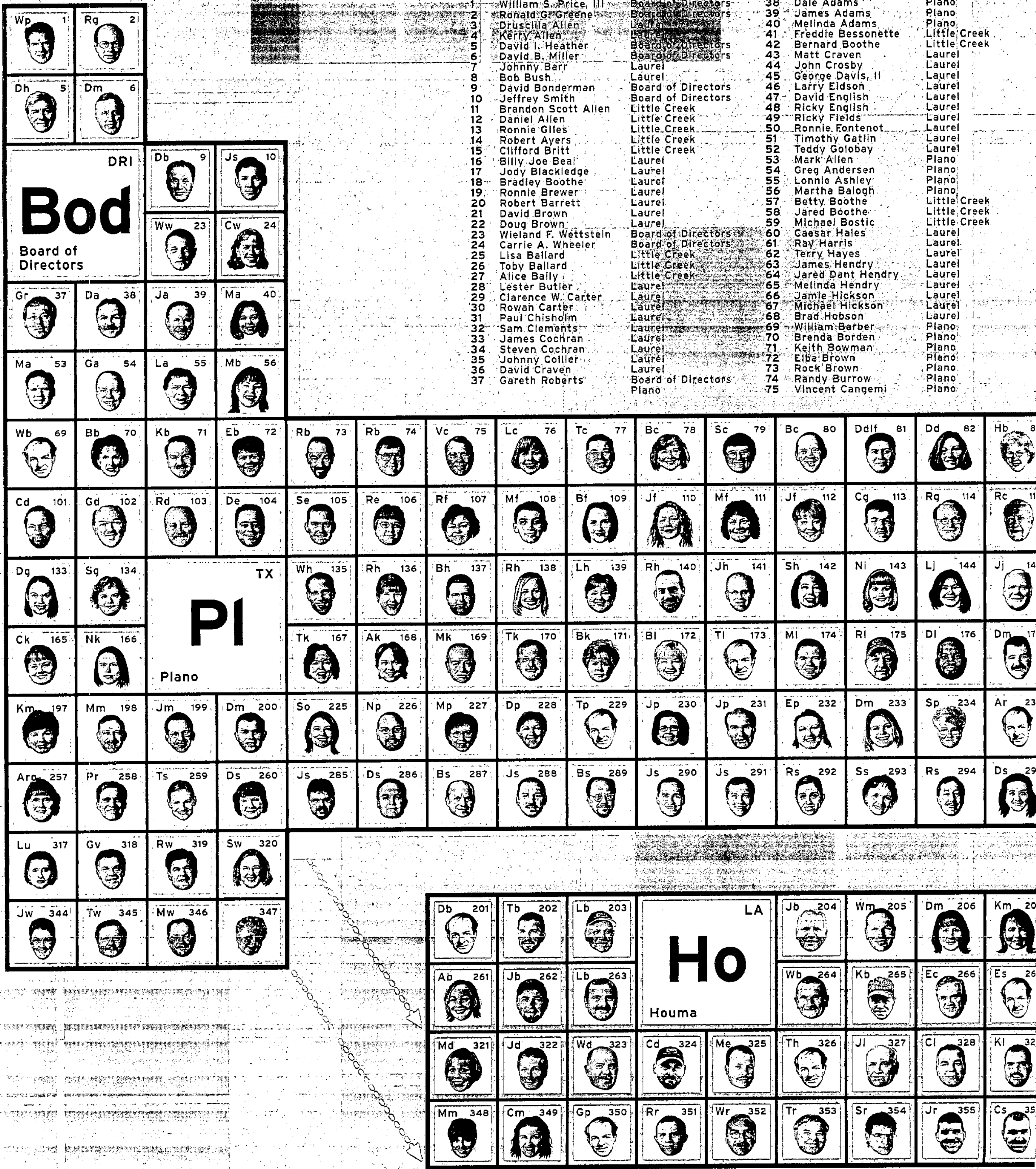


photo of Linus Pauling courtesy of The Linus Pauling Institute, Oregon S

DENBURY PERIODIC TABLE OF THE ELEMENTS

1	William S. Price, III	Board of Directors
2	Ronald G. Greene	Board of Directors
3	Druscilla Allen	Laurel
4	Kerry Allen	Laurel
5	David I. Heather	Board of Directors
6	David B. Miller	Board of Directors
7	Johnny Barr	Laurel
8	Bob Bush	Laurel
9	David Bonderman	Board of Directors
10	Jeffrey Smith	Board of Directors
11	Brandon Scott Allen	Little Creek
12	Daniel Allen	Little Creek
13	Ronnie Giles	Little Creek
14	Robert Ayers	Little Creek
15	Clifford Britt	Little Creek
16	Billy Joe Beal	Laurel
17	Jody Blackledge	Laurel
18	Bradley Boothe	Laurel
19	Ronnie Brewer	Laurel
20	Robert Barrett	Laurel
21	David Brown	Laurel
22	Doug Brown	Laurel
23	Wieland F. Wettstein	Board of Directors
24	Carrie A. Wheeler	Board of Directors
25	Lisa Ballard	Little Creek
26	Toby Ballard	Little Creek
27	Alice Baily	Little Creek
28	Lester Butler	Laurel
29	Clarence W. Carter	Laurel
30	Rowan Carter	Laurel
31	Paul Chisholm	Laurel
32	Sam Clements	Laurel
33	James Cochran	Laurel
34	Steven Cochran	Laurel
35	Johnny Collier	Laurel
36	David Craven	Laurel
37	Gareth Roberts	Board of Directors
		Plano
38	Dale Adams	Plano
39	James Adams	Plano
40	Melinda Adams	Plano
41	Freddie Bessonette	Little Creek
42	Bernard Boothe	Little Creek
43	Matt Craven	Laurel
44	John Crosby	Laurel
45	George Davis, II	Laurel
46	Larry Eidson	Laurel
47	David English	Laurel
48	Ricky English	Laurel
49	Ricky Fields	Laurel
50	Ronnie Fontenot	Laurel
51	Timothy Gatlin	Laurel
52	Teddy Golobay	Laurel
53	Mark Allen	Plano
54	Greg Andersen	Plano
55	Lonnie Ashley	Plano
56	Martha Balogh	Plano
57	Betty Boothe	Little Creek
58	Jared Boothe	Little Creek
59	Michael Bostic	Little Creek
60	Caesar Hales	Laurel
61	Ray Harris	Laurel
62	Terry Hayes	Laurel
63	James Hendry	Laurel
64	Jared Dant Hendry	Laurel
65	Melinda Hendry	Laurel
66	Jamie Hickson	Laurel
67	Michael Hickson	Laurel
68	Brad Hobson	Laurel
69	William Barber	Plano
70	Brenda Borden	Plano
71	Keith Bowman	Plano
72	Elba Brown	Plano
73	Rock Brown	Plano
74	Randy Burrow	Plano
75	Vincent Cangemi	Plano



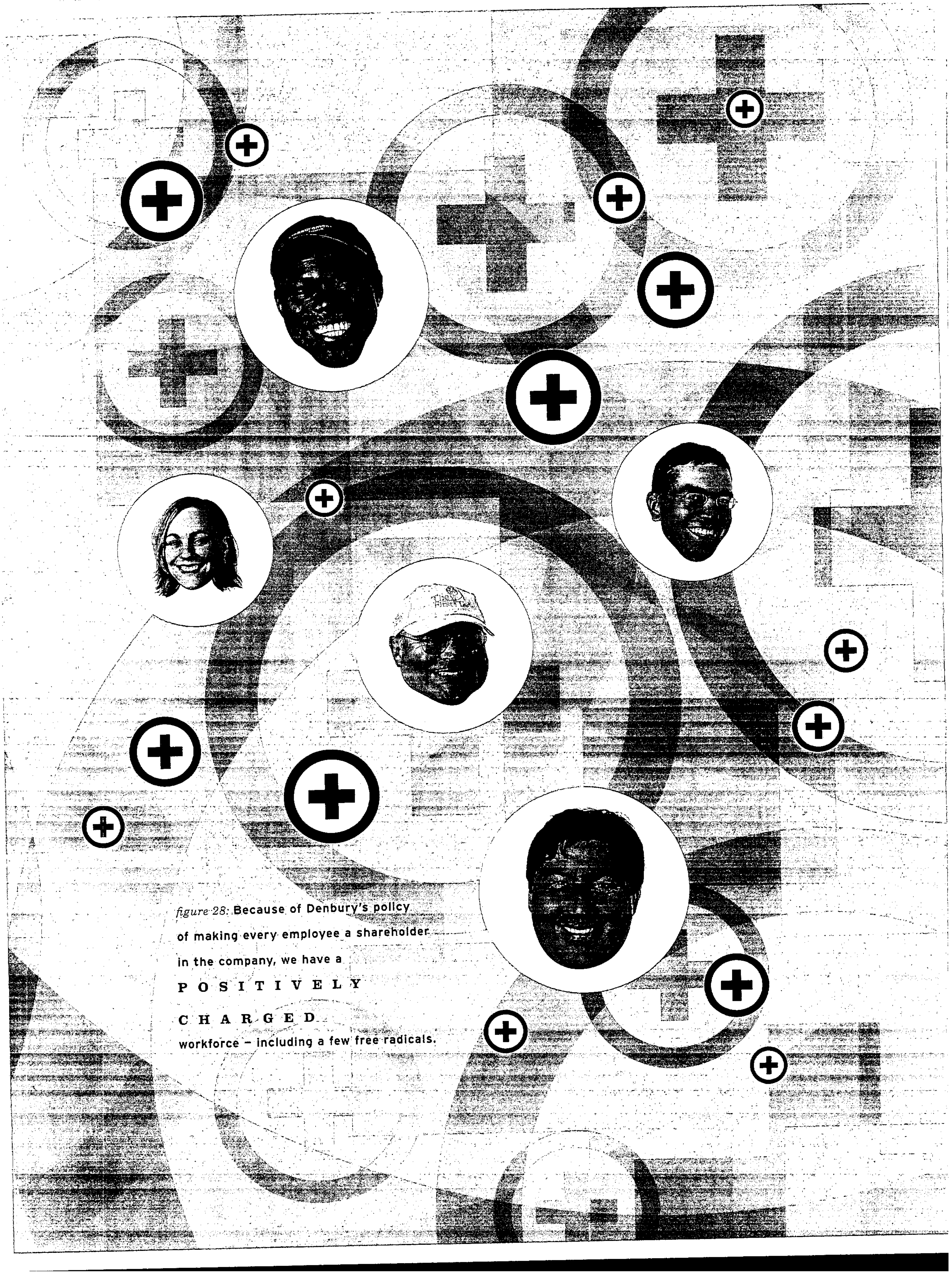


figure 28: Because of Denbury's policy of making every employee a shareholder in the company, we have a P O S I T I V E L Y C H A R G E D workforce – including a few free radicals.

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.

MBBL 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.

MMBBL 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.

PV10 VALUE When used with respect to oil and natural gas reserves, PV10 Value means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect at the determination date, without giving effect to non-property-related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted to 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 which 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

figure 27: Tom Cassard, Plano

C O N T A C T   I N F O R M A T I O N

figure 29: Sharon Oldham, Plano

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Investor Relations:	Laurie Underwood www.denbury.com
Questions re: Press Releases and Stockholder Reports:	Gareth Roberts *President and Chief Executive Officer,* Phil Rykhoek *Senior Vice President and Chief Financial Officer,* Laurie Underwood
Engineering:	Tracy Evans *Senior Vice President, Reservoir Engineering*
Finance:	Phil Rykhoek *Senior Vice President and Chief Financial Officer*
Operations:	Mark Worthey *Senior Vice President of Operations*
Accounting:	Mark Allen *Vice President and Chief Accounting Officer*
Marketing:	Ron Gramling *Vice President of Marketing*
Exploration:	Jim Sinclair *Director of Exploration*
Land:	Ray Dubuisson *Vice President of Land*
Louisiana Division:	George Pecorino Houma, LA
Mississippi Division:	Kerry Allen Laurel, MS
Offshore Division:	Dale Wheeler Covington, LA

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, hold key operating acreage onshore Louisiana and have a growing presence in the offshore Gulf of Mexico areas. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling, and proven engineering extraction processes. Our corporate headquarters are in Dallas, Texas, and we have three primary field offices located in Houma and Covington, Louisiana, and Laurel, Mississippi.

2002 ACQUISITIONS

Acquisition of COHO Gulf Coast Properties

In late August 2002, we acquired COHO Energy, Inc.'s Gulf Coast properties through a bankruptcy auction. Our net purchase price, adjusted for interim production and purchase adjustments to date, was $48.2 million and included nine fields, eight of which are located in Mississippi and one in Texas. We operate all but one of the smaller Mississippi fields. As of December 31, 2002, these properties had net proved reserves of approximately 15.1 million barrels of oil equivalent with net production of approximately 4,000 barrels of oil per day. The Mississippi fields include interests in the Brookhaven, Laurel, Martinville, Soso and Summerland Fields, with working interests in excess of 90%, plus interests in the smaller Bentonia, Cranfield and Glazier Fields. At the time of the acquisition, we hedged nearly 100% of the forecasted proved developed production relating to this acquisition through the end of 2004 with no-cost oil swaps (i.e., forward sales). The average fixed price of these swaps for 2003 is $24.27 per barrel and for 2004 is $22.94 per barrel.

Subsequent to the purchase, we elected to sell several of the acquired properties, primarily to reduce debt. The largest of these is Laurel Field, a field with approximately 7.4 MMBbls of proved reserves as of December 31, 2002. This disposition closed in February 2003. We received $27.0 million and other consideration which included an interest in Atchafalaya Bay Field (where we already own an interest) and seismic over that area. We have reached an agreement to sell two other fields, Bentonia and Glazier Fields, for approximately $2.0 million combined, which is expected to close in late March. Both of these are much smaller fields with approximately 269,000 Bbls of proven reserves at year-end 2002. The proceeds from the sale of Laurel Field were applied to our bank debt, reducing our total debt to $325 million as of February 28, 2003.

We have been able to substantially improve the pricing (relative to NYMEX) for the crude oil sold from the COHO properties since their acquisition. Our sales prices one month after acquiring these properties (October 2002) increased by approximately $3.40 per barrel over the prices that COHO was receiving per barrel earlier in the year. This translated into a 50% increase in the PV10 Value of the acquisition, using constant prices and the futures price strip as of early September 2002. This additional value was possible due to our prominence in the area (we are the largest oil and natural gas producer in Mississippi), coupled with the strategic benefits of acquiring the general partner of Genesis Energy, L.P., which provides us an alternative market for our production because of their pipeline in the area. These improved prices had not changed substantially as of year-end 2002.

Acquisition of Genesis General Partner

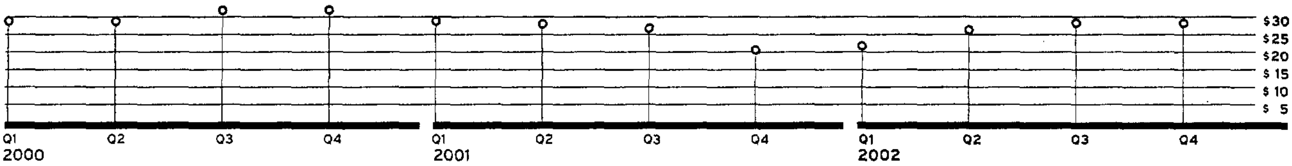
On May 14, 2002, a newly formed subsidiary of Denbury acquired Genesis Energy, L.L.C. (which was converted to Genesis Energy, Inc.), the general partner of Genesis Energy, L.P. ("Genesis"), a publicly traded master limited partnership, for total consideration, including expenses and commissions, of approximately $2.2 million. The general partner owns a 2% interest in the limited partnership. Genesis is engaged in two primary lines of business: crude oil gathering and marketing and pipeline transportation. Genesis was a strategic acquisition for us because of a crude oil pipeline they own in Mississippi near several of our significant oil fields. We believe that Genesis may be in the position to serve as a future financier and developer of our gathering systems, CO_2 and crude oil pipelines and other midstream assets. We are also considering the economic transfer of certain of our assets, such as value of our industrial CO_2 sales, to Genesis in exchange for cash or a combination of cash and partnership units. Whether such a transaction will occur, and if so, the pricing, form and timing, are still being evaluated.

We are accounting for our investment in Genesis under the equity method of accounting, which increased our 2002 net income by $55,000. We have included in the footnotes to the consolidated financial statements summarized financial information of Genesis (see Note 2 to the consolidated financial statements). Genesis Energy, Inc., the general partner of which we own 100%, has guaranteed the bank debt of Genesis, which was $5.5 million as of December 31, 2002, and also included $26.3 million in letters of credit, of which $3.2 million are for Denbury's benefit to secure purchases from Denbury. There are no guarantees by Denbury or any of its other subsidiaries of the debt of Genesis or of Genesis Energy, Inc.

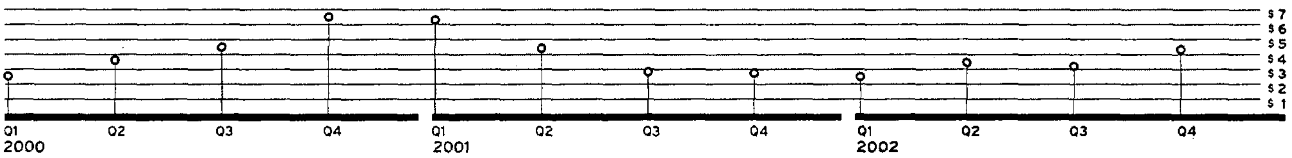
CAPITAL RESOURCES AND LIQUIDITY

During 2002, we spent $99.3 million on oil and natural gas exploration and development expenditures, $16.4 million on CO_2 capital investments, and approximately $56.4 million on oil and natural gas property acquisitions, the largest being the acquisition of properties from COHO Energy, Inc. (see "Acquisition of COHO Gulf Coast properties"). Our cash flow from operations for the year totaled $159.6 million, and we sold properties for aggregate proceeds of approximately $7.7 million. The combined funds of $167.3 million funded all but $4.8 million of our 2002 expenditures, the balance of which was funded by a $9.1 million net increase in bank debt.

NYMEX Crude Oil Price Listings



NYMEX Natural Gas Price Listings



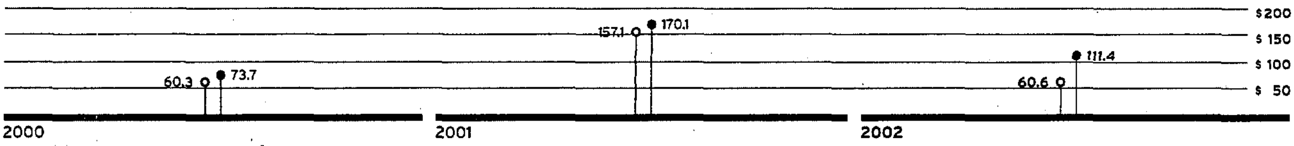
We anticipate that our capital spending during 2003, excluding any possible acquisitions, will be equal to or less than our cash flow generated from operations, as has been our policy since 1999. We currently have budgeted $130 million of new development and exploratory projects for 2003, plus approximately $7.7 million of projects from 2002. Based on current projections, using futures prices in place as of the first part of March 2003, this spending level is expected to be as much as $50 million to $75 million below our forecasted cash flow, depending on 2003 commodity prices. Initially, we plan to use any excess funds generated from operations to pay down debt or to fund, in whole or in part, possible acquisitions, although we may consider increasing our budget later in 2003 if commodity prices remain high and we reach our debt target of $300 million. We review our capital expenditure budget every quarter and make adjustments as necessary to reflect changes in commodity prices and successes or failures in our drilling program. As a result, since 1999, we have been able to keep our capital spending (excluding acquisitions) at levels equal to or below our cash flow from operations.

Although we have a significant inventory of development and exploration projects in-house, on a long-term basis we will need to make acquisitions in order to continue our growth and to replace our production. We are continuing to pursue small acquisitions that are near our CO_2 pipeline in Western Mississippi and Southern Louisiana, plus individual fields in the Gulf of Mexico. Although we now control most of the fields along our CO_2 pipeline, there are a few remaining smaller fields with potential that we do not control, plus we are continuing to acquire additional interests in the fields that we do own. We have targeted the acquisition of offshore blocks, which generally consist of one or two fields, where we see additional potential based on our review of 3D seismic or other geologic and geophysical data. Although we are continuing to pursue acquisitions in our other core areas, including larger acquisitions, this activity is a lower priority for us in 2003 than has been the case historically, given our good inventory of projects in-house and our goal of reducing our debt level. Any acquisitions that we make will likely be funded with either our excess cash flow or bank debt.

Debt

As of September 30, 2002, we had total debt of approximately $375 million following the COHO acquisition. It is our goal to limit our leverage. We generally measure leverage by a debt-to-cash flow ratio, cash flow being defined as cash flow from operations. Our target is a debt-to-cash flow ratio of 2 to 1 or less, using a moderate price deck. In today's commodity price environment, we interpret that to be oil prices in between $22.50 and $25.00 per Bbl and natural gas prices between $3.25 and $3.50 per Mcf. Based on these price assumptions, we would be within our targeted debt-to-cash flow ratio during 2003 if our total debt was reduced to $300 million. Thus, since the third quarter of 2002, we have used a portion of our cash flow from operations and proceeds from

Capital Expenditures In millions of dollars



property sales to reduce our bank debt. During the fourth quarter of 2002, we reduced debt by approximately $25 million, and with proceeds from the sale of Laurel Field in February 2003 we paid down another $25 million of debt, resulting in total debt as of February 28, 2003, of approximately $325 million. Due to the high commodity prices in February 2003 and the resulting amounts due on our hedges that were paid in early March, we borrowed $10 million on March 6, 2003 to fund our hedge payments. We expect to pay back this temporary borrowing after we receive our February production revenues, the majority of which will be received during the third week of March. We expect to achieve our debt goal of $300 million during the latter half of 2003 through the application of excess cash flow from operations, assuming that commodity prices do not change substantially, or possibly by the economic transfer of certain of our assets, such as the value of some of our industrial CO_2 sales, to Genesis.

Debt to Total Capitalization In millions of dollars

In September 2002, we extended the maturity of our bank line from December 2003 to April 2006. Our borrowing base was left unchanged at $220 million and generally the same banks remained in the line, although Bank One became the new administrative agent. Our bank borrowing base is set by our banks at their sole discretion based on various factors, some of which are out of our control, such as the oil and natural gas prices used by the banks to value our reserves. As of March 15, 2003, we had approximately $135 million of bank debt outstanding, leaving us $85 million of current bank line availability. The next borrowing base review by the banks will be as of April 1, 2003, based primarily on year-end reserves. We currently do not anticipate any significant change in the borrowing base at the next redetermination, nor do we currently plan to ask for an increase, even though we believe such a request would be reasonable based upon the additional properties we acquired from COHO. As discussed above, we expect to reduce our total debt to $300 million, which (assuming completion of our subordinated debt refinancing discussed below) would leave us $145 million of availability on our bank line, which we believe is sufficient credit availability, as we do not expect to spend more than our cash flow on development and exploration for the foreseeable future.

On March 17, 2003, we announced a refinancing of our 9% Senior Subordinated Notes due 2008. We sold $225 million of 7.5% Senior Subordinated Notes due 2013 and called our existing $200 million of 9% notes at 104.5% of face value. Closing on the new notes is scheduled for March 25, 2003, subject to the satisfaction of customary closing conditions, and the redemption of the old notes is expected to occur on April 16, 2003. We intend to use the remaining net proceeds from this offering to reduce bank debt. Once completed, the refinancing is expected to save us around $2.6 million per year in interest expense. Assuming completion, we estimate that we will have a charge to earnings in the second quarter of 2003 of approximately $11.25 million, net of related income taxes, from the early retirement of our currently outstanding 9% notes.

Commitments and Obligations

We have no off-balance sheet arrangements, special purpose entities, financing partnerships or guarantees, other than as disclosed in this section, nor do we have any debt or equity triggers based upon our stock or commodity prices. Subject to semi-annual reaffirmation, our bank debt is not due until April 2006, and our $200 million of subordinated debt is due in March 2008. Our only other obligations that are not currently recorded on our balance sheet are our operating leases, which primarily relate to our office space and minor equipment leases and various obligations for development and exploratory expenditures arising from purchase agreements or 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 as forecasted in the proved reserve reports. Our operating lease obligations total $11.7 million in the aggregate and $1.7 million for 2003. We have committed to another operating lease on a portion of our CO_2 facilities equipment at Mallalieu Field with an estimated value of approximately $5.6 million. This lease is expected to commence during mid-2003 with payments of approximately $900,000 per year for seven years. Our capital spending obligations total approximately $13.0 million over the next five years, $2.3 million of which is required in 2003. 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 six months and are part of our ongoing budget process. For a further discussion of our future development costs and proved reserves, see "Results of Operations – Depletion, Depreciation and Site Restoration".

At December 31, 2002, we had a total of $370,000 outstanding in letters of credit. Genesis Energy, Inc., the general partner of which we own 100%, has guaranteed the bank debt of Genesis, which was $5.5 million as of December 31, 2002, and also included $26.3 million in letters of credit of which $3.2 million secured purchases from Denbury. There are no guarantees by Denbury or any of its other subsidiaries of the debt of Genesis or of Genesis Energy, Inc. We do not have any material transactions with related parties other than sales of production to Genesis Energy, L.P. as discussed in Note 2 to our consolidated financial statements. A summary of our obligations discussed above is presented in the following table:

	Expected Maturity Dates					
Amounts in Thousands	**2003**	**2004**	**2005**	**2006**	**2007**	**Thereafter**
Bank debt	$ —	$ —	$ —	$150,000	$ —	$ —
Subordinated debt	—	—	—	—	—	200,000[(1)]
Operating lease obligations	1,708	1,640	1,764	1,766	1,761	3,022
Capital expenditure obligations	2,332	2,500	2,500	2,500	2,500	—
Future development costs on proved reserves, net of capital obligations	70,747	70,290	43,815	16,201	11,912	42,972
Total	$74,787	$74,430	$48,079	$170,467	$16,173	$245,994

(1) See "Debt" section above regarding a refinancing of this debt.

Long-term contracts require us to deliver CO_2 to our industrial CO_2 customers at various contracted prices. Based upon the maximum amounts deliverable as stated in the contracts, we estimate that we may be obligated to deliver up to 387 Bcf of CO_2 to these customers over the next 18 years; however, based on the current level of deliveries, our commitment would be reduced to approximately 250 Bcf. Given the size of our proven CO_2 reserves (approximately 1.6 Tcf), our current production capabilities and our predicted levels of CO_2 usage for our own tertiary flooding program, we are confident that we can meet these delivery obligations.

We have oil price floors, collars and swaps that cover 75% to 85% of our currently anticipated 2003 oil and natural gas production, 40% to 50% of our currently anticipated 2004 oil and natural gas production and a minor portion of our anticipated 2005 natural gas production. Nearly 100% of the forecasted proved developed production from the COHO acquisition has been hedged through 2004 and is included in those production estimates (see also Note 7 to our consolidated financial statements for more detail on these hedges). We have entered into these hedges in order to protect our cash flow, so that a majority of our capital program can be implemented, and so that we can achieve a minimum rate of return on acquisitions, provided that our other assumptions related to the acquisitions are correct. While the current market value of almost all of our hedges is negative (i.e., a liability), they do offer significant protection should commodity prices drop in the future (see also "Market Risk Management" and Note 7 to the Consolidated Financial Statements).

Sources and Uses of Funds

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. 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.

During 2001, we spent approximately $170.1 million on exploration and development activities and approximately $157.1 million on acquisitions (excluding the $42 million CO_2 acquisition), the largest being the acquisition of Matrix. Our exploration and development expenditures included approximately $115.9 million spent on drilling, $18.7 million of geological, geophysical and acreage expenditures and $35.5 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 net incremental debt.

During 2000, we spent approximately $73.7 million on exploration and development activities and approximately $60.3 million on acquisitions. These exploration and development expenditures included approximately $37.8 million spent on drilling, $8.5 million of geological, geophysical and acreage expenditures and $27.4 million spent on facilities and recompletion costs. We funded these exploration and development expenditures with cash flow from operations and funded our acquisitions with cash flow and net incremental bank debt of $46.5 million.

RESULTS OF OPERATIONS

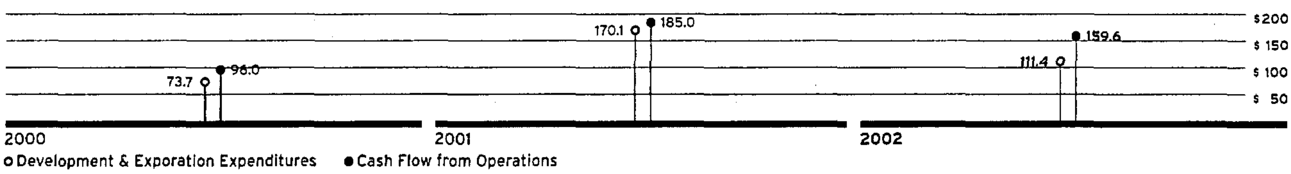
CO_2 Operations

Since 1999, when we acquired our first tertiary oil recovery operation at Little Creek Field, we have increasingly emphasized these types of operations and have acquired several fields which are potential flood candidates since that date. More importantly, in February 2001 we acquired the sources of CO_2 and a pipeline to transport it to these fields. This acquisition included significant carbon dioxide reserves, production, production facilities located near Jackson, Mississippi, and a 183-mile 20-inch pipeline which runs from the Jackson, Mississippi area into southern Louisiana. We acquired nearly 100% of the working interest in the producing CO_2 wells and we operate the properties. During 2002, we drilled another CO_2 producing well, which as of March 5, 2003, was producing around 28 million cubic feet of CO_2 per day. Another well was completed in early March 2003, and we plan to drill two more wells during the remainder of 2003. As of December 31, 2002, we were capable of producing approximately 146 MMcf/d of CO_2 and we expect to increase this capacity to around 200 MMcf/d by the end of 2003. Based on our inventory of potential tertiary recovery projects, we will need to drill additional CO_2 wells in 2004 and beyond to further increase our production capacity to 350 MMcf/d of CO_2 production in order to develop the oil fields along our CO_2 pipeline as planned. 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. As of December 31, 2002, based on a report prepared by DeGolyer and MacNaughton, we estimate that we have approximately 1.6 trillion cubic feet of usable CO_2 reserves, net to our working interest.

Although our oil production from our CO_2 tertiary recovery activities is still modest, we expect it to be an ever increasing portion of our production (see discussion of production below). In order to develop fields which are tertiary flood candidates and increase our oil production, we must continue to increase our CO_2 production. Since we acquired the CO_2 properties in February 2001, CO_2 production has increased from approximately 65 MMcf/d to 146 MMcf/d as of year-end 2002. We plan for this to further increase during the next few years to over 300 MMcf/d. We are using this CO_2 to further develop Little Creek Field, develop Mallalieu Field (acquired in 2001), and we expect to commence tertiary operations at McComb Field during 2003. We have tentatively scheduled tertiary projects at other oil fields along our pipeline, and project that oil production from these tertiary activities will increase from its current level of 3,863 Bbls/d during the fourth quarter of 2002 to as much as 17,000 Bbls/d in 2008. As of December 31, 2002, we had approximately 27.9 MMBbls of proven oil reserves in these fields along our CO_2 pipeline and have identified and estimated significantly more potential in fields that we own. In addition to the development of the fields we currently own along our pipeline, we see other potential tertiary recovery projects in fields we own in Eastern Mississippi, including Heidelberg and Eucutta Fields, plus potential in several large old oil fields in Southern Louisiana which we do not currently own. However, in order to develop these areas we would need additional pipeline transportation facilities, and thus these potential projects are not in our short-term plans.

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. 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 usually require six to twelve months before the field responds to the injection of CO_2. Secondly, as these tertiary projects are more expensive to operate than our other oil fields because of the cost of injecting and recycling the CO_2, 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. These tertiary recovery fields are expected to average between $9 and $10 per BOE in operating expenses over the life of the field, although the cost per BOE is higher at the beginning of each operation. This compares to a cost of around $5 per BOE for a more traditional oil property. Third, while our operating expense on a per BOE basis may rise, our overall oil prices, measured as a discount to NYMEX prices, should continue to improve. These CO_2 operations are all currently conducted in fields that produce light sweet oil and receive oil prices close to (and sometimes actually higher than) NYMEX prices. As this production

Development and Exploration Expenditures vs. Cash Flow from Operations in millions of dollars



becomes a larger percentage of our overall production, our overall average differential to NYMEX should decrease. While our oil prices have historically averaged between $4.00 and $5.00 below NYMEX prices, our 2002 average was $3.73 below NYMEX. This positive trend should continue, subject of course to the normal fluctuations in the marketplace. Despite these high operating costs, due to the high oil price (relative to NYMEX) and the relatively low finding and development costs (anticipated average of approximately $4.00 per BOE), these tertiary recovery operations generate a reasonable rate of return at NYMEX oil prices of $18 to $19 and generate positive cash flow at oil prices significantly lower than that. These tertiary recovery operations are generally lower risk than other types of oil and gas development or exploration, as they are conducted in fields where there has been substantial proven oil production in the past. We anticipate that we will spend between 25% and 50% of our annual development budget on these projects, at least for the next few years, unless there is a significant drop in oil prices or our economics change for some unforeseen reason. We believe that the ownership of our CO_2 reserves provides us a significant strategic advantage in the acquisition of other properties in Mississippi and Louisiana that could be further exploited through tertiary recovery.

It cost us approximately $0.13 per thousand cubic feet to produce our CO_2 during 2002, higher than the $0.07 average for 2001, primarily due to the incremental cost of compression equipment beginning in the third quarter of 2002 and increased maintenance work performed on the facilities during 2002. We allocate the operating expenses to produce our CO_2 and operate and maintain our CO_2 pipeline between the sales to commercial users and CO_2 used for our own account. We expect these costs to be reduced slightly in the future as a result of the incremental CO_2 production from the wells we drilled in 2002 and early 2003 and the anticipated production from the two additional CO_2 wells scheduled later in 2003. The estimated total cost per thousand cubic feet of CO_2 for us during 2002 was approximately $0.16, after inclusion of depreciation and amortization expense, still less than the $0.25 per thousand cubic feet that we were paying before we acquired the properties in February 2001.

In addition to using CO_2 for our own account, we sell CO_2 to third party industrial users under long-term contracts. Our net operating margin from these sales was $4.3 million during 2001 and $6.2 million during 2002. Our average CO_2 production during 2001 and 2002 was approximately 84 million and 104 million cubic feet per day, of which approximately 53% in 2001 and 54% in 2002 was used in our tertiary recovery operations, with the balance sold to third parties for industrial use.

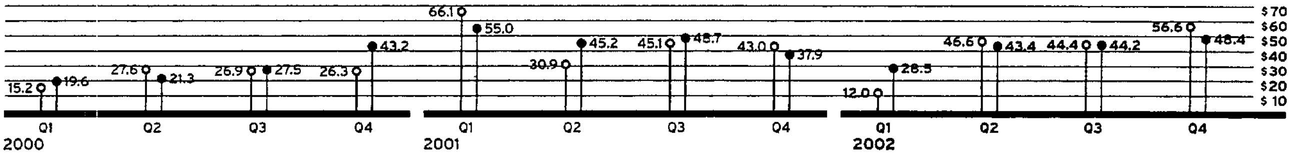
Operating Income

Since 1998, cash flow from operations improved each year until 2002 because of higher commodity prices and production levels. Even though production increased approximately 14% in 2002 over 2001 production levels, our cash flow from operations decreased 14% due to a 24% decline in the average NYMEX natural gas price, a 95% decrease in the proceeds from derivative contracts and a 5% increase in total expenses.

	Year Ended December 31,		
Amounts In Thousands Except Per Share Amounts	**2002**	**2001**	**2000**
Net income	**$ 46,795**	$ 56,550	$142,227
Net income per common share:			
Basic	**$ 0.88**	$ 1.15	$ 3.10
Diluted	**0.86**	1.12	3.07
Adjusted cash flow from operations	**$164,565**	$186,801	$111,555
Net change in assets and liabilities relating to operations	**(4,965)**	(1,754)	(15,583)
Cash flow from operations	**$159,600**	$185,047	$ 95,972

Adjusted cash flow from operations represents cash flow provided by operations before the changes in assets and liabilities. In our discussion of operations herein, we have elected to discuss the two primary components of cash flow provided by operations. Adjusted cash flow from operations 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 this is important to consider separately, as we believe it

Cash Flow from Operations by Quarter in millions of dollars



○ Cash Flow from Operations ● Adjusted Cash Flow from Operations (Cash flow from operations before changes in assets and liabilities. See prior table.)

can often be a better way to discuss changes in operating trends in our business caused by changes in production, prices, operating costs, and so forth, 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 and payment of our obligations has not been a significant issue for our business, but merely a timing issue from one period to the next, as we have very few uncollectible items and pay all of our obligations.

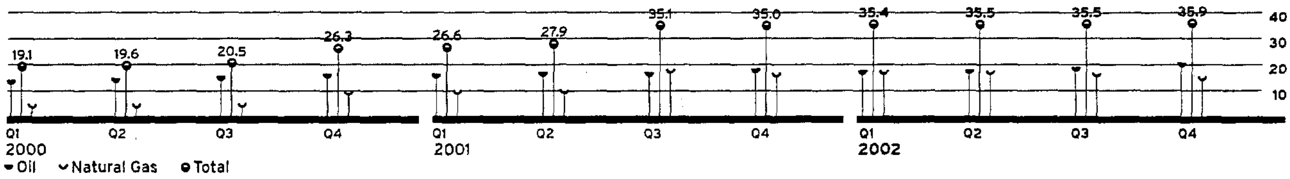
The net change in assets and liabilities that is a part of cash flow provided by operations is also important as it does require or provide additional cash for use in our business; however, we prefer to discuss its effect separately. For instance, as noted above, during 2002 we used approximately $5.0 million of cash to fund a net increase in working capital. This was primarily caused by a high level of drilling and exploitation activity late in 2001 which was not paid (or even due) until 2002. We also used a significant amount of cash flow from operations in 2000, as our net change in assets and liabilities in that year was a negative $15.6 million, primarily relating to unusually high natural gas prices late in 2000, for which we were not paid until the following month (as is normal in our industry), causing a higher than normal increase at year-end 2000 in production receivables. While both are components of a GAAP measure, we believe that it makes sense to discuss them independently.

During 2002, we set another Company record for production. Certain of our operating statistics are set forth in the following chart.

	Year Ended December 31,		
	2002	**2001**	**2000**
Average daily production volume			
Bbls	**18,833**	16,978	15,219
Mcf	**100,443**	85,238	37,078
BOE[1]	**35,573**	31,185	21,399
Operating revenues and expenses (thousands)			
Oil sales	**$153,705**	$ 132,219	$144,230
Natural gas sales	**121,189**	128,179	60,406
Gain (loss) on settlements of derivative contracts[2]	**932**	18,654	(25,264)
Total oil and natural gas revenues	**$275,826**	$ 279,052	$179,372
Lease operating expenses	**$ 71,188**	$ 55,049	$ 38,676
Production taxes and marketing expenses	**11,902**	10,963	8,051
Total production expenses	**$ 83,090**	$ 66,012	$ 46,727
CO_2 sales to industrial customers	**$ 7,580**	$ 5,210	$ —
CO_2 operating expenses	**1,400**	891	—
CO_2 operating margin	**$ 6,180**	$ 4,319	$ —
Unit prices - including impact of hedges[2]			
Oil price per Bbl	**$ 22.27**	$ 21.65	$ 23.50
Gas price per Mcf	**3.35**	4.66	3.57
Unit prices - excluding impact of hedges[2]			
Oil price per Bbl	**22.36**	21.34	25.89
Gas price per Mcf	**3.31**	4.12	4.45
Oil and gas operating revenues and expenses per BOE[1]			
Oil and natural gas revenues (including hedges)	**$ 21.24**	$ 24.52	$ 22.90
Lease operating expenses	**$ 5.48**	$ 4.84	$ 4.94
Production taxes and marketing expenses	**0.92**	0.96	1.02
Total production expenses	**$ 6.40**	$ 5.80	$ 5.96

(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.

Production by Quarter (Average MBOE per day)



Production. From the first quarter of 1999 through the third quarter of 2001, our average daily production increased each quarter, with production in the fourth quarter of 2001 being only slightly less than our third quarter 2001 peak. Our production during 2002 was relatively constant, with only slight growth during the year. Our 2002 production growth was less than it had been in prior years primarily due to a smaller capital budget because of lower commodity prices, particularly late in 2001 and early 2002. In addition, as discussed in "CO_2 Operations" above, our production does not directly correspond with our related capital spending on tertiary recovery projects.

Our production growth over the years has generally been related to acquisitions and subsequent development of the acquired fields. During the last three years, our significant acquisitions of oil and natural gas properties have consisted of the $56.5 million acquisitions of Thornwell, Porte Barre and Iberia Fields in the fourth quarter of 2000, the $4.0 million acquisition of Mallalieu Field in May 2001, the $157.4 million corporate acquisition of Matrix in July 2001, the $2.3 million acquisition of McComb Field in September 2002, and the $48.2 million acquisition of COHO's Gulf Coast properties in August 2002 (see "Acquisition of COHO Gulf Coast Properties" above).

Production by area for 2000, 2001 and each of the quarters of 2002 is listed in the following table.

	Average Daily Production (BOE/d)					
Operating Area	**2000**	**2001**	**First Quarter 2002**	**Second Quarter 2002**	**Third Quarter 2002**	**Fourth Quarter 2002**
Mississippi – non-CO_2 floods	13,179	13,481	**12,423**	**12,124**	**13,232**	**15,703**
Mississippi – CO_2 floods	2,018	2,560	**3,839**	**4,278**	**3,895**	**3,863**
Onshore Louisiana	5,878	9,268	**8,405**	**7,717**	**8,224**	**7,859**
Offshore Gulf of Mexico	201	5,691	**10,550**	**11,229**	**9,863**	**8,287**
Other	123	185	**144**	**178**	**292**	**182**
Total Company	21,399	31,185	**35,361**	**35,526**	**35,506**	**35,894**

Our average production from our non-CO_2 flood properties in Mississippi decreased slightly during 2002, excluding the increases attributable to the acquisition of COHO properties, due to general production declines at most of our significant fields and a reduced level of capital expenditures in this area during 2002. Heidelberg Field, located in Eastern Mississippi, is Denbury's largest single field. At the time of its acquisition in December 1997, Heidelberg Field was producing approximately 2,800 BOE/d. Production under our ownership has subsequently averaged 3,760 BOE/d, 5,708 BOE/d, 7,310 BOE/d, 7,908 BOE/d and 7,479 BOE/d for 1998, 1999, 2000, 2001 and 2002. During 1998, our primary emphasis was implementation of the field's largest waterflood unit, the East Heidelberg Waterflood Unit, plus other developmental drilling. During 1999, we began to see response from our waterflood efforts. We added other waterflood units during 1999 and 2001 and also expanded our drilling for natural gas at Heidelberg in the Selma Chalk formation during the second half of 1999. As a result, natural gas production at Heidelberg increased from 0.5 MMcf/d in 1998 to 1.0 MMcf/d in 1999, 3.8 MMcf/d in 2000 and 7.4 MMcf/d in 2001. Our activity in 2002 was generally related to continued maintenance of the waterfloods in progress, plus the drilling of eight additional natural gas wells in the second half of the year as a result of the higher natural gas prices. Average production at our Heidelberg Field during 2002 was 5% lower than production levels there in 2001. Overall production from this field is expected to remain relatively flat or slightly decline as the waterfloods appear to have reached a plateau, although there may be periodic spikes in the natural gas production as a result of the recently drilled additional natural gas wells.

Since 1999, when we acquired our first tertiary oil recovery operation at Little Creek Field, we have increasingly emphasized these types of operations and have acquired several fields that are potential CO_2 flood candidates since that date (see the discussion of

"CO_2 Operations" above). Although production from our CO_2 activities is still modest, we expect it to be an ever increasing portion of our production. It has generally increased each period, although in the third and fourth quarters of 2002, average production on our tertiary recovery properties was slightly less than the second quarter 2002 average due to a temporary lack of deliverability of CO_2. We have increased our CO_2 production since that time and are continuing to drill additional CO_2 wells and believe that we have sufficiently increased our CO_2 production to meet our current needs for our tertiary recovery operations, although we will require additional CO_2 production in the future (see "CO_2 Operations" above for further information). As such, production from these fields has begun to respond, averaging approximately 4,019 Bbls/d during February 2003, a 4% increase over the fourth quarter 2002 average. Production at Little Creek Field, our oldest and currently our largest tertiary recovery operation, has also increased since we acquired it in August 1999. At the time of acquisition, Little Creek was producing approximately 1,350 BOE/d, with a 1999 annual average production rate of 587 BOE/d, due to our ownership for a partial year. Since acquiring the field, we have completed phase III of the CO_2 flood and implemented phases IV and V, resulting in gradual production increases. Production from Little Creek Field averaged 2,018 BOE/d for 2000, 2,462 BOE/d for 2001, and 3,393 BOE/d in 2002. We are continuing to expand our tertiary recovery operations at Little Creek and anticipate that production will further increase at this field throughout 2003.

Production from our onshore Louisiana area was generally down year over year, although there have been fluctuations up and down on a quarter-to-quarter basis primarily as a result of drilling activity at Thornwell Field. Production at Thornwell Field during 2002 averaged 3,910 BOE/d, a 9% decrease from production levels in 2001. The majority of the production at Thornwell is short-lived natural gas production, and thus volumes can fluctuate significantly from period to period depending on the level of activity, the timing of well completions, and other factors. Overall, we believe the Thornwell acquisition in October of 2000 has performed well, as we recovered our acquisition cost within the first year of ownership. We are continuing development and exploration activities at Thornwell Field in 2003, although at a lower level than in 2002.

Our natural gas production has significantly increased during the last couple of years, primarily due to the acquisition of the offshore Gulf of Mexico properties owned by Matrix Oil and Gas in July 2001. Our development and exploration activities on these properties was minimal in 2002 due to the low natural gas prices at the beginning of the year. Thus offshore production generally declined during the latter half of 2002, although annual average production here was still higher in 2002 than in 2001. Production was also hurt by two storms, Tropical Storm Isidore in September 2002 and Hurricane Lili in October 2002. Although it is difficult to measure the exact impact of the storms, our offshore production declined by 1,366 BOE/d between the second and third quarters of 2002 and further declined by 1,576 BOE/d in the fourth quarter of 2002, a significant portion of which relates to the shut-in of production caused by the two storms. The storm also caused other indirect declines in production, both onshore and offshore, by delaying several projects because of unusually wet conditions, high water, and other storm-related effects. As an example, the incremental CO_2 production from a well we drilled in the third quarter was delayed because the wet conditions made it difficult to install a pipeline to hook up the well. These types of delays caused our production to be less than we had originally anticipated in the last half of the year. During 2003, with anticipated higher natural gas prices, we are spending almost 30% of our budget offshore, second only to our CO_2 operations expenditures. Since the acquisition of Matrix in July 2001, our production has generally been close to 50/50 oil and natural gas and we anticipate that balance to remain near 50/50 in the near future based on our current development plans.

Revenue. Our oil and natural gas revenues increased 56% between 2000 and 2001, but decreased slightly (1%) in 2002. The growth in 2001 revenues was primarily due to a 46% increase in production, as our net per BOE prices were almost the same. During 2002, production increased 14%, but the decline in natural gas prices caused our net per BOE price to decline by 7%, thereby limiting the revenue increase between years. Between 2000 and 2001, the overall increase in production volumes contributed $92.8 million in revenue, or a 52% increase, and the incremental cash receipts from hedges contributed $43.9 million, or a 25% increase, partially offset by an overall decrease of $37.0 million in commodity prices (or a negative 21%). Between 2001 and 2002, revenues decreased by 1%, due primarily to lower hedging receipts. The overall increase in production volumes contributed $36.6 million in revenue, or a 13% increase, more than offset by the combined 14% reduction in revenues due to a decrease in cash receipts from hedges of $17.7 million (a negative 6%) and an overall decrease of $22.1 million in commodity prices (or a negative 8%).

During 2000, we paid out $13.3 million ($2.39 per Bbl) on our oil hedges and $11.9 million ($0.88 per Mcf) on our natural gas hedges. In contrast, during 2001, we collected $1.9 million ($0.31 per Bbl) on our oil hedges and $16.7 million ($0.54 per Mcf) on our natural gas hedges. During 2002, we paid out $0.6 million ($0.09 per Bbl) on our oil hedges but collected a net $1.5 million ($0.04 per Mcf) on our natural gas hedges. See "Market Risk Management" for a further discussion of our hedging activities.

Operating Expenses. Oil and natural gas lease operating expenses decreased 2% on a per BOE basis between 2000 and 2001, as a result of the addition of the Matrix properties in July 2001 and savings resulting from our ownership of CO_2 assets purchased in February 2001. These savings were partially offset by overall higher service and equipment costs in the industry during the year. The Matrix properties predominately consisted of natural gas, which typically have a lower per unit operating cost than oil properties. We also reduced operating expenses by approximately $2.6 million during 2001 because of our acquisition of the CO_2 source fields and operations in February 2001 (see "CO_2 Operations" above).

Our oil and natural gas lease operating expenses increased 13% on a per BOE basis between 2001 and 2002. This increase was primarily due to higher than usual workover expenses, principally offshore on the Matrix properties, repairs relating to storm damage from Hurricane Lili that was not covered by insurance or was part of the insurance deductible amount, higher per BOE costs due to the lost production from that storm and Tropical Storm Isidore, and higher than average operating expenses on the properties acquired from COHO in August 2002, as significant repairs and clean-up were required. Lastly, as discussed under "CO_2 Operations" above, operating expenses are gradually increasing as a result of the increased tertiary recovery operations. Lease operating expenses increased on a gross basis by $16.1 million, or 29%, between the two years.

Operating expenses increased slightly in our non-CO_2 flood Mississippi properties from $6.07 per BOE in 2001 to $6.31 per BOE for 2002, primarily due to the addition of the COHO properties in late August 2002. Operating expenses for the COHO properties averaged $9.91 per BOE and are expected to remain unusually high during the first half of 2003 as we continue to clean up these fields and perform necessary repairs and maintenance to return these fields to proper working condition. In comparison, operating costs per BOE for our long-standing non-CO_2 Mississippi properties were $5.21 per BOE in 2000, lower than the $6.07 per BOE in 2001, with the increase primarily due to higher overall costs in the industry in 2001. Offshore operating expenses were $5.08 per BOE for 2002, higher than the 2001 average of $3.46 per BOE. The higher operating expenses generally correlate with the increased number of workovers in 2002 and lower production than anticipated due to the suspended production as a result of Tropical Storm Isidore and Hurricane Lili. In addition, we had approximately $750,000 of repairs due to Hurricane Lili which were not covered by insurance or were part of our insurance deductible expensed in the fourth quarter of 2002. Operating costs per BOE for 2000 in our limited offshore operations do not provide a meaningful basis for comparison due to the lower level of activity prior to the Matrix acquisition. Operating expenses at Little Creek Field were $9.45 per BOE in 2002, slightly less than the $9.80 per BOE for 2001, due primarily to higher production rates. In comparison, operating costs per BOE were $11.15 at Little Creek in 2000, with the savings primarily due to the lower cost of CO_2 after the CO_2 acquisition in February 2001 and higher overall production rates.

Production taxes and marketing expenses on a per BOE basis decreased 6% between 2000 and 2001 and 4% between 2001 and 2002. The decrease in 2002 was primarily due to a reduction in the Louisiana gas severance tax rate effective July 1, 2002. The decrease in production taxes and marketing expenses in 2001 was due to the addition of the Matrix properties, a portion of which are tax exempt due to their offshore location, partially offset by higher marketing expenses on the offshore properties relating to incremental processing and transportation costs.

General and Administrative Expenses

During the last three years, general and administrative ("G&A") expenses on a per BOE basis have fluctuated between $0.89 and $1.09 per BOE. Our gross G&A expense increased each year, but with our significant production increases, net G&A expense on a per BOE basis has remained around $1.00 per BOE.

	Year Ended December 31,		
Amounts in Thousands Except Per BOE and Employee Data	**2002**	**2001**	**2000**
Gross G&A expense	**$ 40,149**	$ 33,727	$ 24,941
Operator overhead charges	**(23,857)**	(20,328)	(13,684)
Capitalized exploration expense	**(5,325)**	(4,102)	(3,202)
	10,967	9,297	8,055
State franchise taxes	**1,459**	877	467
Net G&A expense	**$ 12,426**	$ 10,174	$ 8,522
Average G&A expense per BOE	**$ 0.96**	$ 0.89	$ 1.09
Employees as of December 31	**356**	320	242

We have grown for the last several years from both acquisitions and our own internal development and exploration work. As a result, we have had general increases in consultant fees, hired additional personnel, and have given salary increases and bonuses each year. In particular, we hired additional personnel as part of the Matrix acquisition in July 2001 and COHO acquisition in August 2002. Our bonuses, as authorized by our board of directors, were at the upper end of the bonus plan range in all three years, 2000 through 2002, based primarily on our overall financial and operating results.

Partially offsetting the overall increase in gross G&A costs are the increases in operator overhead charges and capitalized exploration expenses. The respective well operating agreements allow us, when we are the operator, to charge a specified overhead rate during the drilling phase and to charge a monthly fixed overhead rate for each producing well. As a result of the general escalation in activity each year and the addition of more operated wells from our acquisitions, this recovery of G&A increased from $13.7 million in 2000 to $20.3 million in 2001 and to $23.9 million in 2002. Capitalized exploration costs also increased each year as a result of the increase in gross G&A expense and the additional technical personnel added as part of the Matrix and COHO acquisitions. As a result, net G&A expense increased only 19% in 2001 and 22% in 2002, even though gross G&A expense increased 35% and 19% respectively. On a per BOE basis, G&A costs decreased 18% in 2001 but increased 8% in 2002, both changes less than the absolute change in G&A due to the higher production volumes each year.

Interest and Financing Expenses

	Year Ended December 31,		
Amounts In Thousands Except Per BOE Data	2002	2001	2000
Interest expense	**$ 26,833**	$ 22,335	$ 15,255
Non-cash interest expense	**(2,659)**	(1,665)	(945)
Cash interest expense	**24,174**	20,670	14,310
Interest and other income	**(1,746)**	(849)	(2,279)
Net cash interest expense	**$ 22,428**	$ 19,821	$ 12,031
Average net cash interest expense per BOE	**$ 1.73**	$ 1.74	$ 1.54
Average debt outstanding	**$350,556**	$264,792	$160,884
Average interest rate(1)	**6.9%**	7.8%	8.9%

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

We began 2000 with $152.5 million of total outstanding debt. During 2000, we borrowed $61 million to fund property acquisitions and related hedges, but repaid $14.5 million from cash flow, ending the year with $199 million of long-term debt outstanding. During 2001, we had total bank borrowings of $146.0 million, primarily to fund our acquisition of Matrix ($100.0 million) and the CO_2 acquisition ($42.0 million). We repaid a total of $79.1 million during the year, (i) $13.0 million of which related to excess cash flow generated from operations early in the year given the unusually high natural gas prices and (ii) $65.9 million of which represented the net proceeds of our issuance of Series B 9% Senior Subordinated Notes due 2008, in August 2001. These notes were issued at a discount with an estimated yield to maturity of 10 7/8%. Our total outstanding debt increased from $199 million as of December 31, 2000, to $340.9 million as of December 31, 2001 (excluding the unamortized issue discount), a 71% increase. Our average interest rate decreased in 2001 due to an overall drop in interest rates, even though we issued an additional $75 million of subordinated debt in August at a relatively high interest rate. Overall, we had a 65% increase in net cash interest expense in 2001, but only a 13% increase on a BOE basis due to our overall production increases.

During 2002, we borrowed $49.1 million, primarily to fund the COHO acquisition, and repaid $40.0 million during the year from excess cash flow, leaving us with $350 million of total debt outstanding as of December 31, 2002 (excluding the discount). On average our debt balance was $85.8 million higher in 2002 than in 2001 due to the acquisitions during both periods. Our average interest rate was 0.9% lower in 2002 primarily due to decreases throughout 2001 and 2002 in interest rates on our variable rate bank debt, offset in part by the issuance of $75 million of subordinated debt in August 2001 which carries a higher interest rate than the bank debt it replaced. Net cash interest expense on a per BOE basis decreased 1% between 2001 and 2002 due to our higher production, an increase in interest and other income in 2002, and a higher percentage of interest expense relating to non-cash amortization following the issuance of subordinated debt at a discount in August 2001.

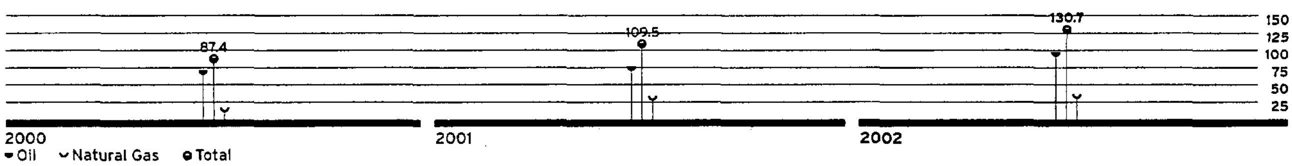
Depletion, Depreciation and Site Restoration

Depletion, depreciation and amortization ("DD&A") was at its lowest rate on a per BOE basis in our history in 1999 as a result of the full cost pool writedowns in 1998. Since that time, our DD&A rate has increased each year as our overall finding cost has been greater than the abnormally low rate in 1999, particularly the finding cost of certain of our acquisitions.

	Year Ended December 31,		
Amounts In Thousands Except Per BOE Data	**2002**	**2001**	**2000**
Depletion and depreciation	**$87,728**	$66,402	$34,530
Depreciation of CO_2 assets	**1,858**	1,572	—
Site restoration provision	**2,951**	1,946	560
Depreciation of other fixed assets	**1,699**	1,425	1,124
Total DD&A	**$94,236**	$71,345	$36,214
DD&A per BOE:			
Oil and natural gas properties	**$ 6.98**	$ 6.01	$ 4.48
CO_2 assets and other fixed assets	**0.28**	0.26	0.14
Total DD&A cost per BOE	**$ 7.26**	$ 6.27	$ 4.62

The NYMEX oil prices used in our reserve reports have ranged from $26.80 per Bbl as of December 31, 2000 to $19.84 per Bbl as of December 31, 2001, and $31.20 per Bbl as of December 31, 2002. Natural gas prices have been even more volatile, moving from $9.78 per Mcf at December 31, 2000, to $2.57 per Mcf at December 31, 2001, then to $4.79 per Mcf at December 31, 2002. Even though we require our proved undeveloped properties to be economic at relatively low commodity prices, so that their inclusion in our reserves is not dependent on commodity prices, the fluctuating prices do impact DD&A because of the effect commodity prices have on the economic lives of our properties (and thus the changes in reserve quantities). Between 2000 and 2001, the significant reduction in commodity prices, particularly those for oil, reduced the economic lives of our properties and reduced reserve quantities by 8.3 MMBOE. Overall, during 2001 we showed a 25% increase in reserve quantities as we added 41.8 MMBOEs from acquisitions, other development work, and upward revisions. Our total proved reserve quantities increased from 87.4 MMBOE as of December 31, 2000, to 109.5 MMBOE as of December 31, 2001.

Proved Reserves (MMBOE)



During 2002, prices rebounded, increasing our reserve quantities by approximately 3.5 MMBOE due solely to the price changes. During 2002, we also added 35.9 MMBOE, primarily from our COHO acquisition and additional reserves booked on our CO_2 tertiary flood properties. Our total proved reserve quantities increased from 109.5 MMBOE as of December 31, 2001, to 130.7 MMBOE as of December 31, 2002.

Reserve quantities are only one side of the DD&A equation, with capital expenditures and projected future development costs making up the remainder of the calculation. During 2001 our DD&A rate increased from $4.62 per BOE in 2000 to an average rate of $6.27 per BOE ($7.19 per BOE during the second half of the year after the Matrix acquisition), primarily as result of our acquisition of Matrix in July 2001. This acquisition had a higher than average cost per BOE ($13.28 per BOE, including unevaluated property costs) because of the high natural gas price environment. The acquisition itself looks positive, as we have increased our reserve quantities from this acquisition since the acquisition closed in July 2001 by 22% (or 55% by adding back production), natural gas prices are currently above price levels at the time of acquisition, and we still have most of the probable and possible reserves remaining to exploit. In addition, the PV10 Value of these properties at December 31, 2002, is approximately $101.7 million more than our net unrecovered cost.

The DD&A calculation is also affected by our future development costs, which increased from $95.1 million as of December 31, 2000, to $178.5 million as of December 31, 2001, to $268.3 million as of December 31, 2002. These future development costs represent the estimated cost necessary to recover our undeveloped reserves, with the largest single increases relating to the 10.4 MMBbls of reserves recorded at Mallalieu Field in 2001 and 8.3 MMBbls recorded at McComb Field in 2002. As the overall percentage of undeveloped reserves relative to our total reserves has increased from approximately 24% in 2001 to approximately 34% in 2002, so has the amount of future development costs. In addition, at two of our fields, McComb and North Padre Island, pending further development work and/or testing, the reserve quantities booked at year-end are only a portion of what we believe to be each field's ultimate potential. Since the currently booked proven reserves must bear the total cost of these fields' required facilities, the future development costs per BOE are higher here than what we ultimately expect them to be. In summary, even though reserve quantities were 19% higher in 2002 than in 2001, as a result of the other factors discussed above, our DD&A rate per BOE of $7.26 in 2002 was relatively unchanged from the $7.19 DD&A rate per BOE during the last half of 2001 (the rate after the Matrix acquisition).

We provide for the estimated future costs of well abandonment and site reclamation, net of any anticipated salvage, on a unit-of-production basis. This provision is included in DD&A expense and has increased each year, along with the general increase in the number of our properties, especially the acquisition of our offshore properties. Beginning January 1, 2003, we are required to adopt Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations." With the adoption of this new accounting standard, we will record the estimated future abandonment cost as an asset and liability on our balance sheet. While there may be some adjustments as a result of the adoption of this accounting pronouncement, we do not expect the adoption to materially impact our income statements going forward as these abandonment costs have historically been amortized as part of our DD&A.

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 writedowns in 2000, 2001 or 2002 and do not expect to have any such writedowns in the foreseeable future at the current commodity price levels.

Income Taxes

For the year ended December 31, 2000, we had taxable income of $27.6 million, but were able to offset this income with our net operating loss carryforwards ("NOLs"). We did incur $558,000 of current income tax expense during 2000 which related to alternative minimum taxes that could not be offset by NOLs. For the year ended December 31, 2000, a normal tax provision would have resulted in income tax expense of $27.7 million. However, we utilized a portion of our deferred tax assets and the corresponding valuation allowance to offset this provision. We also reevaluated the remaining balance of $67.9 million relating to our net deferred tax asset as of December 31, 2000. We concluded that it was more likely than not that there would be sufficient future taxable income that would allow us to realize the tax benefits of our deferred tax assets, resulting in a deferred tax benefit of $67.9 million and a net deferred tax asset balance as of December 31, 2001, of $67.9 million, none of which was impaired.

With the adjustment to deferred taxes in 2000, we began booking a normal tax provision in 2001. In 2001, we began to recognize the amount of enhanced oil recovery credits that we had earned to date from our tertiary projects, which totaled $5.3 million at year-end 2001. As a result of these credits, our effective tax provision for 2001 was lowered from 37% to 30.5%. Most of this provision was deferred, as we were able to offset our taxable income with our NOLs. The current portion of the tax provision related to alternative minimum taxes that could not be offset by NOLs.

Prior to 2002, our effective tax rate was 37%. During 2002, we determined that our effective rate had increased to 38% and adjusted our provision for the year accordingly. The net effective tax rate for 2002 was lower than 38%, primarily due to the recognition of enhanced oil recovery credits which lowered our overall tax expense. During 2002 we utilized almost all of our alternative minimum tax loss carryforwards. Therefore, in 2003 and beyond, a portion of our tax provision will be current as we will become an alternative minimum tax payer. As of December 31, 2002, we had approximately $84.9 million of regular tax net operating loss carryforwards remaining, to shelter our future income against regular tax.

The overall current income tax credit for 2002 is 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.

Amounts In Thousands Except Per Unit Amounts	Year Ended December 31, 2002	2001	2000
Current income tax expense (benefit)	**$ (406)**	$ 640	$ 558
Deferred income tax provision (benefit)	**23,926**	24,184	(67,852)
Total income tax provision (benefit)	**$ 23,520**	$ 24,824	$(67,294)
Average income tax provision (benefit) per BOE	**$ 1.81**	$ 2.18	$ (8.59)
Net operating loss carryforwards	**84,891**	100,601	112,690
Net deferred tax asset (liability)	**$(21,777)**	$(17,433)	$ 67,852
Valuation allowance	**—**	—	—
Total net deferred tax asset (liability)	**$(21,777)**	$(17,433)	$ 67,852

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.

Per BOE Data	Year Ended December 31, 2002	2001	2000
Oil and natural gas revenues	**$21.17**	$22.88	$26.13
Gain (loss) on settlements of derivative contracts	**0.07**	1.64	(3.23)
Lease operating expenses	**(5.48)**	(4.84)	(4.94)
Production taxes and marketing expenses	**(0.92)**	(0.96)	(1.02)
Production netback	**14.84**	18.72	16.94
CO_2 operating margin	**0.48**	0.38	—
General and administrative expenses	**(0.96)**	(0.89)	(1.09)
Net cash interest expense	**(1.73)**	(1.74)	(1.54)
Current income taxes and other	**0.04**	(0.06)	(0.07)
Changes in assets and liabilities	**(0.38)**	(0.15)	(1.99)
Cash flow from operations	**12.29**	16.26	12.25
DD&A	**(7.26)**	(6.27)	(4.62)
Deferred income taxes	**(1.84)**	(2.12)	8.66
Amortization of derivative contracts and other non-cash hedging adjustments	**0.24**	(2.90)	—
Changes in assets and liabilities and other non-cash items	**0.17**	—	1.87
Net income	**$ 3.60**	$ 4.97	$18.16

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. The fair value of our bank debt is considered to be the same as the carrying value because the interest rate is based on floating short-term interest rates. The fair value of the subordinated debt is based on quoted market prices. None of our debt has any triggers or covenants regarding our debt ratings with rating agencies.

Amounts In Thousands	Expected Maturity Dates 2003-2005	2006	2007	2008	Carrying Value	Fair Value
Variable rate debt:						
Bank debt	$ —	$150,000	$ —	$ —	$150,000	$150,000
The weighted-average interest rate on the bank debt at December 31, 2002 is 3.2%.						
Fixed rate debt:						
Subordinated debt, net of discount	$ —	$ —	$ —	$194,889	$194,889	$206,580
The interest rate on the subordinated debt is a fixed rate of 9%.						

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. We generally attempt 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. When we make an acquisition, we 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 predominately with collars, although for the recent 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.

At December 31, 2002, our derivative contracts were recorded at their fair value, which was a net liability of approximately $35.6 million, a decrease of approximately $59.1 million from the $23.5 million fair value asset recorded as of December 31, 2001. This change is the result of (i) a decrease in the fair market value of our hedges due to an increase in oil and natural gas commodity prices between December 31, 2001, and December 31, 2002, (ii) the settlement received from our former Enron hedge positions in February 2002, and (iii) the expiration of certain derivative contracts during 2002 for which we recorded amortization expense of $9.7 million. Information regarding our current hedging positions and historical hedging results is included in Note 7 to the Consolidated Financial Statements.

Based on NYMEX natural gas futures prices at December 31, 2002, we would expect to make future cash payments of $17.2 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 $3.7 million, and if futures prices were to increase by 10% we would expect to pay $36.1 million. Based on NYMEX crude oil futures prices at December 31, 2002, we would expect to pay $7.5 million on our crude oil commodity hedges. If crude oil futures prices were to decline by 10%, we would expect to receive $7.6 million under our crude oil commodity contracts, and if crude oil futures prices were to increase by 10%, we would expect to pay $25.2 million under our crude oil commodity hedges. Since December 31, 2002, prices increased substantially on both oil and natural gas, through at least early March 2003.

CRITICAL ACCOUNTING 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. We consider our most critical accounting policies are those related to property and equipment and hedging activities.

Property, Plant and Equipment, Depletion and Depreciation and Oil and Natural Gas Reserves

We follow the full-cost method of accounting for oil and natural gas properties. Under this method of 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 the financial statement disclosures.

The changes in commodity prices also affect our reserve quantities. For instance, between 2000 and 2001, the significant reduction in commodity prices, particularly oil, reduced the economic lives of our properties and reduced reserve quantities by 8.3 MMBOE. During 2002, both commodity prices rebounded, resulting in an increase to our reserve quantities of approximately 3.5 MMBOE. These changes in quantities affect our DD&A rate and the combined effect of changes in quantities and commodity prices impacts our full-cost ceiling test calculation. 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 the 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 do not book proved undeveloped reserves unless the project is scheduled in our development budget (or at least the commencement of the project in the case of longer-term multi-year projects such as waterfloods and tertiary recovery projects). In most cases, our development budget is prepared only for the next year or so. 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 we have interpreted during the last several years as $18.50 per Bbl of oil and $2.50 per Mcf of natural gas. This also can have the effect of eliminating certain projects in a high price environment, as was the case at year-end 2002. (See "CO_2 Operations" and "Depletion, Depreciation, and Site Restoration" 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.

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 must 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 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.

With the significant changes in commodity prices over the last two years, the fair value of our hedges has gone from an asset valued at $23.5 million at year-end 2001 to a liability of $35.6 million as of year-end 2002. While most of this change in value is recorded in other comprehensive income, 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. If these hedges were deemed to no longer qualify for hedge accounting at some point in time, as happened to our hedges with Enron in 2001 (see below), then the change in value would be reflected in our income statement.

In order to qualify for hedge accounting, the changes in fair value or cash flows of the hedging instruments and the hedged items must have a high degree of correlation (i.e., be effective). 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.

All of our current derivative hedging instruments qualify for hedge accounting. However, during 2001 we had derivative contracts with Enron that initially qualified for hedge accounting, but their status changed when Enron filed bankruptcy, causing us to change our accounting treatment of this asset before the hedge expired. As these hedges no longer qualified for hedge accounting, we recognized a pre-tax write down of $24.4 million in the fourth quarter of 2001. As demonstrated by the prior year impact, these adjustments can be material to our financial statements and are unpredictable.

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.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

In July 2001, the Financial Accounting Standards Board ("FASB") issued 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 and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value 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. The standard is effective for us beginning January 1, 2003. Although we are still finalizing our evaluation of the impact of adopting SFAS No. 143, we currently believe that the adoption of this standard will result in an increase to property and equipment and to our accrual for site reclamation costs, and a charge to income as a cumulative effect adjustment from a change in accounting principle, net of tax. Historically, we have made an accrual each period for our future retirement obligations as part of our DD&A calculation. The total amount accrued at December 31, 2002 was $6.8 million and is recorded in our Consolidated Balance Sheets as "Provision for site reclamation costs." We are still reviewing certain legal obligations and the estimated future periods in which these costs will be incurred, which information is necessary to calculate the present value of our future retirement obligations. We presently estimate our future retirement obligations, before any salvage value recoupment and before the obligations are discounted for the time value of money, at approximately $75 million. We estimate the net salvage value for the equipment associated with these asset retirement obligations to be approximately $40 million, which will be included in our future DD&A calculations.

In November 2002, FASB issued Interpretation ("FIN") No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness by Others." FIN No. 45 requires that a guarantor must recognize, at the inception of the guarantee, a liability for the fair value of the obligation that it has undertaken in issuing a guarantee. FIN 45 also addresses the disclosure requirements that a guarantor must include in its financial statements for guarantees issued. The disclosure requirements of this interpretation are effective for financial statements ending after December 15, 2002. The initial recognition and measurement provisions of this interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. We have made all relevant disclosures regarding our guarantees.

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, capital expenditures, drilling activity, acquisition plans and proposals and dispositions, development activities, cost savings, production efforts and volumes, hydrocarbon reserves, hydrocarbon prices, liquidity, regulatory matters, mark-to-market values, and competition. Such forward-looking statements generally are accompanied by words such as "plan," "estimate," "expect," "predict," "anticipate," "projected," "should," "assume," "believe" 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, the uncertainty of drilling results and reserve estimates, operating hazards, acquisition risks, requirements for capital, general economic conditions, competition and government regulations, as well as the risks and uncertainties 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, except with respect to pages 2, 8-11, 14, 16-17, 19-20, 22-25, and 27-70 which are incorporated into the Company's Annual Report on Form 10-K.

INDEPENDENT AUDITORS' REPORT

TO THE STOCKHOLDERS OF DENBURY RESOURCES INC.

We have audited the consolidated balance sheets of Denbury Resources Inc. and subsidiaries (the "Company") as of December 31, 2002 and 2001 and the related consolidated statements of operations, stockholders' equity (deficit) and cash flows for each of the three years in the period ended December 31, 2002. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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 consolidated financial statements present fairly in all material respects, the financial position of Denbury Resources Inc. and subsidiaries as of December 31, 2002 and 2001 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Dallas, Texas
March 3, 2003

CONSOLIDATED BALANCE SHEETS

Amounts in Thousands Except Share Amounts	December 31, 2002	2001
ASSETS		
Current assets		
Cash and cash equivalents	**$ 23,940**	$ 23,496
Accrued production receivables	**34,458**	23,411
Related party accrued production receivable – Genesis	**3,334**	—
Trade and other receivables, net of allowance of $207 and $233	**16,846**	31,924
Derivative assets	**—**	23,458
Deferred tax asset	**49,886**	989
Total current assets	**128,464**	103,278
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved	**1,245,896**	1,098,263
Unevaluated	**45,736**	44,521
CO_2 properties and equipment	**62,370**	45,555
Less accumulated depletion and depreciation	**(609,917)**	(520,332)
Net property and equipment	**744,085**	668,007
Investment in Genesis	**2,224**	—
Other assets	**20,519**	18,703
Total assets	**$ 895,292**	$ 789,988
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	**$ 49,281**	$ 66,498
Oil and gas production payable	**17,309**	13,440
Derivative liabilities	**29,289**	—
Total current liabilities	**95,879**	79,938
Long-term liabilities		
Long-term debt	**344,889**	334,769
Provision for site reclamation costs	**6,845**	4,318
Derivative liabilities	**6,281**	—
Deferred tax liability	**71,663**	18,422
Other	**2,938**	3,373
Total long-term liabilities	**432,616**	360,882
Commitments and contingencies (Note 8)		
Stockholders' equity		
Preferred stock, $.001 par value, 25,000,000 shares authorized; none issued and outstanding	**—**	—
Common stock, $.001 par value, 100,000,000 shares authorized; 53,539,329 and 52,956,825 shares issued and outstanding at December 31, 2002 and December 31, 2001, respectively	**54**	53
Paid-in capital in excess of par	**395,906**	391,557
Accumulated deficit	**(9,875)**	(56,670)
Accumulated other comprehensive income (loss)	**(19,288)**	14,228
Total stockholders' equity	**366,797**	349,168
Total liabilities and stockholders' equity	**$ 895,292**	$ 789,988

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF OPERATIONS

Amounts in Thousands Except Per Share Amounts	Year Ended December 31, 2002	2001	2000
Revenues			
Oil, natural gas and related product sales			
Unrelated parties	**$251,972**	$260,398	$204,636
Related party – Genesis	**22,922**	—	—
CO_2 sales	**7,580**	5,210	—
Gain (loss) on settlements of derivative contracts	**932**	18,654	(25,264)
Interest income and other	**1,746**	849	2,279
Total revenues	**285,152**	285,111	181,651
Expenses			
Lease operating expenses	**71,188**	55,049	38,676
Production taxes and marketing expenses	**11,902**	10,963	8,051
CO_2 operating expenses	**1,400**	891	—
General and administrative expenses	**10,967**	9,297	8,055
Interest expense	**26,833**	22,335	15,255
Depletion and depreciation	**94,236**	71,345	36,214
Franchise taxes	**1,459**	877	467
Loss on Enron related assets	**—**	25,164	—
Amortization of derivative contracts and other non-cash hedging adjustments	**(3,093)**	7,816	—
Total expenses	**214,892**	203,737	106,718
Equity in net income of Genesis	**55**	—	—
Income before income taxes	**70,315**	81,374	74,933
Income tax provision (benefit)			
Current income taxes	**(406)**	640	558
Deferred income taxes	**23,926**	24,184	(67,852)
Net income	**$ 46,795**	$ 56,550	$142,227
Net income per common share			
Basic	**$ 0.88**	$ 1.15	$ 3.10
Diluted	**0.86**	1.12	3.07
Weighted average common shares outstanding			
Basic	**53,243**	49,325	45,823
Diluted	**54,365**	50,361	46,352

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Amounts in Thousands	Year Ended December 31, 2002	2001	2000
Cash flow from operating activities:			
Net income	**$ 46,795**	$ 56,550	$142,227
Adjustments needed to reconcile to net cash flow provided by operations:			
Depletion and depreciation	**94,236**	71,345	36,214
Deferred income taxes	**23,926**	24,184	(67,852)
Non-cash loss on Enron related assets	**—**	25,164	—
Amortization of derivative contracts and other non-cash hedging adjustments	**(3,093)**	7,816	—
Amortization of debt issue costs and other	**2,701**	1,742	966
Changes in assets and liabilities relating to operations:			
Accrued production receivable	**(14,381)**	19,399	(21,691)
Trade and other receivables	**15,078**	(17,622)	(2,797)
Derivative assets and liabilities	**8,427**	(28,043)	—
Other assets	**133**	863	(5,109)
Accounts payable and accrued liabilities	**(17,217)**	23,560	8,586
Oil and gas production payable	**3,869**	(2,213)	5,038
Other liabilities	**(874)**	2,302	390
Net cash provided by operating activities	**159,600**	185,047	95,972
Cash flow used for investing activities:			
Oil and natural gas expenditures	**(99,273)**	(170,109)	(73,736)
Acquisitions of oil and gas properties	**(56,364)**	(97,871)	(60,285)
Investment in Genesis	**(2,170)**	—	—
Acquisition of CO_2 assets and capital expenditures	**(16,445)**	(45,555)	—
Net purchases of other assets	**(3,688)**	(1,799)	(1,629)
Increase in restricted cash	**(909)**	(3,496)	(322)
Proceeds from sales of oil and gas properties	**7,688**	—	2,932
Net cash used for investing activities	**(171,161)**	(318,830)	(133,040)
Cash flow from financing activities:			
Bank repayments	**(40,000)**	(79,130)	(14,500)
Bank borrowings	**49,130**	146,000	61,000
Issuance of subordinated debt	**—**	68,528	—
Issuance of common stock	**3,594**	2,594	1,491
Costs of debt financing	**(719)**	(3,026)	(398)
Other	**—**	20	—
Net cash provided by financing activities	**12,005**	134,986	47,593
Net increase in cash and cash equivalents	**444**	1,203	10,525
Cash and cash equivalents at beginning of year	**23,496**	22,293	11,768
Cash and cash equivalents at end of year	**$ 23,940**	$ 23,496	$ 22,293

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY

Dollar Amounts in Thousands	Common Stock ($.001 Par Value) Shares	Amount	Paid-In Capital in Excess of Par	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Comprehensive Income (Loss)
Balance – December 31, 1999	45,718,486	$ 46	$ 327,829	$(255,447)	$ —	$ 72,428	
Issued pursuant to employee stock purchase plan	218,493	—	1,305	—	—	1,305	
Issued pursuant to employee stock option plan	40,458	—	186	—	—	186	
Issued pursuant to directors compensation plan	2,544	—	19	—	—	19	
Net income and comprehensive income	—	—	—	142,227	—	142,227	$142,227
Balance – December 31, 2000	45,979,981	46	329,339	(113,220)	—	216,165	142,227
Issued pursuant to employee stock purchase plan	189,485	—	1,546	—	—	1,546	
Issued pursuant to employee stock option plan	209,600	—	1,048	—	—	1,048	
Issued pursuant to directors compensation plan	7,829	—	63	—	—	63	
Issued in Matrix acquisition	6,569,930	7	59,188	—	—	59,195	
Tax benefit from stock options	—	—	373	—	—	373	
Net income	—	—	—	56,550	—	56,550	56,550
Other comprehensive income (loss):							
Change in accounting principle for derivative contracts, net of tax of $594	—	—	—	—	1,012	1,012	1,012
Reclassification adjustments for derivative contracts, net of tax of $594	—	—	—	—	(1,012)	(1,012)	(1,012)
Change in fair value of derivative contracts, net of tax of $8,356	—	—	—	—	14,228	14,228	14,228
Balance – December 31, 2001	52,956,825	53	391,557	(56,670)	14,228	349,168	70,778
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**	
Net income	**—**	**—**	**—**	**46,795**	**—**	**46,795**	**46,795**
Other comprehensive income (loss):							
Reclassification adjustments for derivative contracts, net of tax of $4,919	**—**	**—**	**—**	**—**	**(7,838)**	**(7,838)**	**(7,838)**
Amortization of derivative contracts, net of tax of $3,598	**—**	**—**	**—**	**—**	**6,066**	**6,066**	**6,066**
Change in fair value of derivative contracts, net of tax of $18,857	**—**	**—**	**—**	**—**	**(31,744)**	**(31,744)**	**(31,744)**
Balance – December 31, 2002	**53,539,329**	**$ 54**	**$395,906**	**$ (9,875)**	**$(19,288)**	**$366,797**	**$13,279**

See Notes to Consolidated Financial Statements.

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES

Organization and Nature of Operations

Denbury Resources Inc. is a Delaware corporation, organized under *Delaware General Corporation Law,* engaged in the acquisition, development, operation and exploration of oil and natural gas properties. 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. In 2001, we acquired carbon dioxide ("CO_2") reserves that are used in our tertiary oil recovery operations. In addition, we sell some CO_2 to third parties for 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 public limited partnership. We account for our 2% interest in Genesis under the equity method. 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 2 for more information regarding the Genesis acquisition and summary financial information. All material intercompany balances and transactions have been eliminated.

Oil and Natural Gas Operations

a) Capitalized costs. We follow the full-cost method of accounting for oil and natural gas properties. Under this method, all costs related to acquisitions, exploration and development of oil and natural gas reserves are capitalized and accumulated in a single cost center representing our activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells and general and administrative expenses directly related to exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. Proceeds received from disposals are credited against accumulated costs except when the sale represents a significant disposal of reserves, in which case a gain or loss is recognized.

b) Depletion and depreciation. The costs capitalized, including production equipment, are depleted or depreciated on the unit-of-production method, based on proved oil and natural gas reserves as determined by independent petroleum engineers. Oil and natural gas reserves are converted to equivalent units based upon the relative energy content which is six thousand cubic feet of natural gas to one barrel of crude oil.

c) Site reclamation. Estimated future costs of well abandonment and site reclamation, including the removal of production facilities at the end of their useful life, are provided for on a unit-of-production basis. Costs are based on engineering estimates of the anticipated method and extent of site restoration, valued at year-end prices, net of estimated salvage value, and in accordance with the current legislation and industry practice. The annual provision for future site reclamation costs is included in depletion and depreciation expense and reported under long-term liabilities in the Consolidated Balance Sheets as "Provision for site reclamation costs."

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 (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 10 for information on our proved oil and natural gas reserves and the basis on which they are recorded.

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, 2002 and 2001, 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. On January 1, 2001, we adopted Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. Upon adoption of SFAS No. 133, we recorded a $1.6 million increase in our derivative assets to reflect the fair value of our derivative instruments in place at that time and a corresponding increase to accumulated other comprehensive income of approximately $1.0 million, net of tax, in the transition adjustment. This transition adjustment was reclassified out of accumulated other comprehensive income to earnings over the remainder of 2001.

SFAS No. 133 requires that every derivative instrument be 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 hedging instruments 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 redesignated, deferred gains or losses on the hedging instrument are recognized in earnings immediately.

Receipts and payments resulting from settlements of derivative hedging instruments are recorded in "Gain (loss) on settlements of derivative 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 "Amortization of derivative contracts and other non-cash hedging adjustments" under expenses in the Consolidated Statements of Operations. Denbury's hedging activities are further discussed in Note 7.

Comprehensive Income (Loss)

Our comprehensive income (loss) information is included in our Consolidated Statements of Stockholders' Equity. All of our adjustments to other comprehensive income and the balances in accumulated other comprehensive income (loss) at December 31, 2002 and 2001 relate to our derivative hedging contracts which are discussed in Note 7.

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 and trade and accrued production receivables in addition to the derivative hedging instruments discussed above. Our cash equivalents represent high-quality securities placed with various investment grade institutions. This investment practice limits our exposure to concentrations of credit risk. Our trade and accrued production receivables are dispersed among various customers and purchasers; therefore, concentrations of credit risk are limited. Also, most of our significant purchasers are large companies with excellent credit ratings. If customers are considered a credit risk, letters of credit are the primary security obtained to support lines of credit. We attempt to minimize our credit risk exposure to the counterparties of our derivative hedging contracts through formal credit policies, monitoring procedures and diversification.

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 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 costs" and the expenses related to our own uses are recorded in "Lease operating costs" 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.

Cash Equivalents

We consider all highly liquid investments to be cash equivalents if they have maturities of three months or less at the date of purchase.

Restricted Cash

At December 31, 2002 and 2001, we had approximately $8.7 million and $7.8 million, respectively, of restricted cash held in escrow for future site reclamation costs. This restricted cash is included in "Other Assets" in the Consolidated Balance Sheets.

Net Income Per Common Share

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

For each of the three years in the period ended December 31, 2002, 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:

	Year Ended December 31,		
Amounts in Thousands	2002	2001	2000
Weighted average common shares – basic	**53,243**	49,325	45,823
Effect of diluted securities:			
Stock options	**1,122**	1,036	529
Weighted average common shares – diluted	**54,365**	50,361	46,352

We did not include in the diluted shares outstanding calculation 1.7 million options in 2002, 1.8 million options in 2001 and 1.6 million options in 2000 because their inclusion would be antidilutive as their exercise prices exceeded the average market price of our common stock during the respective periods.

Stock Options

We issue stock options to all of our employees under our stock option plan which is described more fully in Note 6. We account for our stock option plan utilizing the recognition and measurement principles of Accounting Principles Board Opinion 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," in accounting for our stock option plan.

	Year Ended December 31,		
	2002	**2001**	**2000**
Net income: (thousands)			
Net income, as reported	**$46,795**	$56,550	$142,227
Less: stock-based compensation expense applying fair value based method, net of related tax effects	**2,866**	2,763	2,401
Pro forma net income	**$43,929**	$53,787	$139,826
Net income per common share:			
As reported:			
Basic	$ 0.88	$ 1.15	$ 3.10
Diluted	0.86	1.12	3.07
Pro forma:			
Basic	$ 0.83	$ 1.09	$ 3.05
Diluted	0.83	1.09	3.05

The fair value of each option grant was estimated with the Black-Scholes option pricing model using the following weighted average assumptions:

	2002	**2001**	**2000**
Risk-free interest rate	**4.05%**	4.64%	6.5%
Expected life	**5 years**	5 years	5 years
Expected volatility	**61.4%**	63.4%	55.0%
Dividend yield	**—**	—	—

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 the fair value of financial derivative instruments and the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties and the related present value of estimated future net cash flows therefrom.

Reclassifications

Certain prior period amounts have been reclassified to conform with the current year presentation. Such reclassifications had no impact on our reported net income, current assets, total assets, current liabilities, total liabilities or stockholders' equity.

Recently Issued Accounting Pronouncements

SFAS No. 143, "Accounting for Asset Retirement Obligations," requires that the fair value of a liability for an asset retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value 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. The standard is effective for us beginning January 1, 2003. Although we are still finalizing our evaluation of the impact of adopting SFAS No. 143, we currently believe that the adoption of this standard will result in an increase to property and equipment and to our accrual for site reclamation costs, and a charge to income as a cumulative effect adjustment from a change in accounting principle, net of tax. Historically, we have made an accrual each period for our future retirement obligations as a part of our DD&A calculation. The total amount accrued at December 31, 2002 was $6.8 million and is recorded in our Consolidated Balance Sheets as "Provision for site reclamation costs." We are still reviewing certain legal obligations and the estimated future periods in which these costs will be incurred, which information is necessary to calculate the present value of our future retirement obligations. We presently estimate our future retirement obligations, before any salvage value recoupment and before the obligations are discounted for the time value of money, at approximately $75 million. We estimate the net salvage value for the equipment associated with these asset retirement obligations to be approximately $40 million, which will be used in our future DD&A calculations.

In November 2002, FASB issued Interpretation ("FIN") No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness by Others." FIN No. 45 requires that a guarantor must recognize, at the inception of the guarantee, a liability for the fair value of the obligation that it has undertaken in issuing a guarantee. FIN 45 also addresses the disclosure requirements that a guarantor must include in its financial statements for guarantees issued. The disclosure requirements of this interpretation are effective for financial statements ending after December 15, 2002. The initial recognition and measurement provisions of this interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. We have made all relevant disclosures regarding our guarantees.

NOTE 2. ACQUISITIONS

COHO Gulf Coast Properties

In August 2002, we acquired COHO Energy, Inc's Gulf Coast properties auctioned in the U.S. Bankruptcy Court in Dallas, Texas. Our net purchase price, adjusted for interim cash flow from the June 1, 2002 effective date, together with purchase adjustments through December 31, 2002, was $48.2 million and included nine fields, eight of which are located in Mississippi and one in Texas. We operate all but one of the smaller Mississippi fields. At December 31, 2002, these properties had proved reserves of approximately 15.1 million barrels of oil equivalent with net production of approximately 4,000 barrels of oil per day. The Mississippi fields include 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. We have hedged nearly 100% of the forecasted proved developed production relating to this acquisition through the end of 2004 with no-cost oil swaps (i.e., forward sales). The average fixed price of these swaps for 2003 is $24.27 per barrel and for 2004 is $22.94 per barrel.

Subsequent to December 31, 2002, we have sold or have reached an agreement to sell certain of these fields, which is further discussed in Note 12.

Genesis Energy, L.L.C.

On May 14, 2002, a newly formed subsidiary of Denbury acquired Genesis Energy, L.L.C. (which was converted to Genesis Energy, Inc.), the general partner of Genesis Energy, L.P. ("Genesis"), a publicly traded master limited partnership, for total consideration, including expenses and commissions, of approximately $2.2 million. The general partner owns a 2% interest in the limited partnership. Genesis is engaged in two primary lines of business: crude oil gathering and marketing and pipeline transportation, primarily in Mississippi, Texas, Alabama and Florida.

We are accounting for our 2% ownership in Genesis under the equity method as we have significant influence over the limited partnership; however, our control is limited under the general partnership agreement and therefore we do not consolidate Genesis. Our equity in Genesis' net income for 2002 was $55,000, representing 2% of Genesis' net income for the period from May 14, 2002 through December 31, 2002. Genesis Energy, Inc., the general partner of which we own 100%, has guaranteed the bank debt of Genesis, which was $5.5 million as of December 31, 2002, and also included $26.3 million in letters of credit of which $3.2 million are for Denbury's benefit to secure purchases from Denbury. There are no guarantees by Denbury or any of its other subsidiaries of the debt of Genesis or of Genesis Energy, Inc. Our investment of $2.2 million exceeded our percentage of net equity in the limited partnership at the time of acquisition by approximately $1.0 million, which represents goodwill and is not subject to amortization.

Genesis has historically been a purchaser of our crude oil and we anticipate future purchases of our crude oil production by Genesis. For the year ended December 31, 2002, we recorded sales to Genesis of $30.0 million and at December 31, 2002, had a production receivable from Genesis of $3.3 million. Our sales to Genesis from the period May 14, 2002 through December 31, 2002 were $22.9 million and are shown separately as related party sales in our Consolidated Statements of Operations.

Summarized financial information of Genesis Energy, L.P., is as follows:

Amounts in Thousands	Year Ended December 31, 2002
Revenues	$911,806
Cost of sales	888,691
Other expenses	18,023
Net income	$ 5,092

Amounts in Thousands	December 31, 2002
Current assets	$ 92,830
Non-current assets	44,707
Total assets	$137,537
Current liabilities	$ 96,220
Non-current liabilities	5,500
Partners' capital	35,817
Total liabilities and partners' capital	$137,537

Other 2002 Acquisitions

We completed other minor acquisitions in 2002 for approximately $12.4 million. These acquisitions consisted of an additional CO_2 well and reserves for $4.3 million, McComb Field, a new tertiary oil recovery field, for $2.3 million, and other minor acquisitions.

Matrix Oil and Gas, Inc.

On July 10, 2001, we completed the acquisition of Matrix Oil & Gas, Inc.("Matrix"), an independent oil and gas company based in Covington, Louisiana. Under the merger agreement, we paid a total of approximately $157.4 million, comprised of $98.2 million (62%) in cash and $59.2 million (38%) in the form of 6.6 million shares of Denbury's common stock, including post-closing adjustments. The purchase price was allocated to the net assets acquired based on estimated fair market values at the date of acquisition, with the predominant amount allocated to oil and gas properties. As part of our purchase price allocations, we recorded a deferred income tax liability of $53.1 million to reflect the difference between the book and carryover tax basis of the properties acquired, and we allocated $30.0 million of the purchase price to unevaluated property to reflect the significant probable and possible reserves that were identified in the acquisition. Based on subsequent drilling activity and our ongoing evaluation of the undeveloped prospects, we have reclassified $6.0 million of the original $30.0 million to developed property as of December 31, 2002. Denbury's financial statements include the operations of Matrix from July 1, 2001.

The following pro forma information reflects the consolidated financial results of operations for the years ended December 31, 2001 and 2000, based upon adjustments to the historical financial statements of Denbury and the historical financial statements of Matrix as if the acquisition had occurred at the beginning of such periods presented. The effects of other acquisitions in 2002 and 2001 were not significant for inclusion in the pro forma presentation. Pro forma amounts are not necessarily indicative of what the actual results would have been.

	Year Ended December 31,	
Amounts In Thousands Except Per Share Amounts	**2001**	**2000**
Revenues	$324,401	$214,473
Expenses	234,097	147,409
Net income	62,243	137,387
Income per common share:		
Basic	$ 1.18	$ 2.62
Diluted	1.16	2.60

CO_2 Acquisition

On February 2, 2001, we purchased certain CO_2 reserves, production and associated assets from a division of Airgas, Inc., for $42.0 million. The acquisition included ten producing CO_2 wells and production facilities located near Jackson, Mississippi, and a 183-mile, 20-inch pipeline that is currently transporting CO_2 to our tertiary oil recovery operations at Little Creek and Mallalieu Fields, as well as to other commercial customers.

Other 2001 Acquisitions

During 2001 we completed other minor acquisitions totaling approximately $5.0 million.

2000 Acquisitions

During the fourth quarter of 2000, Denbury completed acquisitions totaling $56.5 million in the Thornwell, Porte Barre and Iberia Fields located in southwestern Louisiana. Approximately $10.0 million of these acquisition costs were initially recorded as unevaluated property costs at December 31, 2000. The Company also completed other minor acquisitions totaling $3.8 million during 2000.

NOTE 3. PROPERTY AND EQUIPMENT

	December 31,	
Amounts In Thousands	**2002**	**2001**
Oil and natural gas properties		
Proved properties	**$1,245,896**	$1,098,263
Unevaluated properties	**45,736**	44,521
Total	**1,291,632**	1,142,784
Accumulated depletion and depreciation	**(606,488)**	(518,760)
Net oil and natural gas properties	**685,144**	624,024
CO_2 properties	**62,370**	45,555
Accumulated depletion and depreciation	**(3,429)**	(1,572)
Net CO_2 properties	**58,941**	43,983
Net property and equipment	**$ 744,085**	$ 668,007

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 have been discovered or impairment has occurred. A summary of the unevaluated properties excluded from oil and natural gas properties being amortized at December 31, 2002 and 2001 and the year in which they were incurred follows:

	December 31, 2002				December 31, 2001		
	Costs Incurred During:				Costs Incurred During:		
Amounts In Thousands	2002	2001	2000	Total	2001	2000	Total
Property acquisition costs	$12,459	$22,128	$228	$34,815	$34,195	$3,688	$37,883
Exploration costs	7,526	2,938	457	10,921	5,395	1,243	6,638
Total	$19,985	$25,066	$685	$45,736	$39,590	$4,931	$44,521

Costs are transferred into the amortization base on an ongoing basis as the projects are evaluated and proved reserves established or impairment determined. 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. As of December 31, 2002, approximately $24.0 million of the total unevaluated property balance of $45.7 million related to the Matrix acquisition. These costs will be transferred into the amortization base as the undeveloped areas are tested. We anticipate that the majority of this activity should be completed over the next three to five years.

NOTE 4. NOTES PAYABLE AND LONG-TERM INDEBTEDNESS

	December 31,	
Amounts In Thousands	2002	2001
Senior bank loan	**$150,000**	$140,870
9% Senior Subordinated Notes due 2008	**125,000**	125,000
9% Series B Senior Subordinated Notes due 2008	**75,000**	75,000
Discount on 9% Series B Subordinated Notes due 2008	**(5,111)**	(6,101)
Total long-term debt	**$344,889**	$334,769

Senior Bank Loan

In September 2002, we entered into a Third Amended and Restated Credit Agreement with our banks which extended the maturity of our bank credit facility from December 2003 to April 2006. In conjunction with the amended credit agreement, Bank One became the new administrative agent bank. The facility borrowing base remained at $220 million, leaving a borrowing capacity of approximately $70 million as of December 31, 2002, and there were no other significant changes as part of the amendment.

The 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, 2002. Our bank credit facility provides for a semi-annual redetermination of the borrowing base on April 1 and October 1. At the April 2001 redetermination, our borrowing base was increased from $150 million to $200 million and was further increased at the October 2001 redetermination to $220 million. It has not changed since that time.

As of December 31, 2002, we had $150.0 million outstanding under the facility, at a weighted average interest rate of 3.2%, $370,000 of letters of credit outstanding and a borrowing base of $220 million. The next scheduled redetermination of the borrowing base will be as of April 1, 2003, based on December 31, 2002 assets and proved reserves.

Subordinated Debt

On February 26, 1998, Denbury Management Inc. ("DMI"), a wholly owned subsidiary of Denbury at that time, issued $125 million in aggregate principal amount of 9% Senior Subordinated Notes due 2008 which require only semi-annual interest payments until maturity. In April 1999, DMI was merged into Denbury Resources Inc., which expressly assumed all liabilities of DMI, including the 9% Senior Subordinated Notes. These notes contain certain debt covenants, including covenants that limit (i) indebtedness, (ii) certain restricted payments including dividends, (iii) sale/leaseback transactions, (iv) transactions with affiliates, (v) liens, (vi) asset sales and (vii) mergers and consolidations. We received net proceeds from the debt offering of approximately $121.8 million before offering expenses.

During August 2001, Denbury issued an additional $75 million of subordinated debt in a private placement at 91.371% of face amount for an effective yield of 10.875%. The notes were issued under a separate indenture, but on terms substantially identical to the existing 9% Senior Subordinated Notes due 2008. The net proceeds to us were approximately $65.9 million. These notes were subsequently exchanged for a like principal amount of publicly registered notes.

Interest payments on our $200.0 million of subordinated debt are payable on March 1 and September 1. Our subordinated debt is callable at our option beginning March 1, 2003 at the following redemption prices: 104.5% on March 1, 2003, 103.0% on March 1, 2004, 101.5% on March 1, 2005 and 100% on March 1, 2006 and thereafter. There are no sinking fund requirements for our subordinated debt.

On March 17, 2003, we announced a refinancing of our $200 million of 9% Senior Subordinated Notes (see Note 12).

Indebtedness Repayment Schedule

Our indebtedness as of December 31, 2002 is repayable as follows:

Amounts In Thousands	
Year	
2003	$ —
2004	—
2005	—
2006	150,000
2007	—
Thereafter (2008)	200,000
Total indebtedness	$350,000

NOTE 5. INCOME TAXES

Our income tax provision (benefit) is as follows:

Amounts In Thousands	Year Ended December 31, 2002	2001	2000
Current income tax expense (benefit)			
Federal	**$ (419)**	$ 614	$ 558
State	**13**	26	—
Total current income tax expense (benefit)	**(406)**	640	558
Deferred income tax expense (benefit)			
Federal	**23,926**	24,184	(67,852)
State	**—**	—	—
Total deferred income tax expense (benefit)	**23,926**	24,184	(67,852)
Total income tax expense (benefit)	**$23,520**	$24,824	$(67,294)

Our income tax benefit for 2000 was primarily the result of the elimination of the valuation allowance on our net deferred tax assets as of December 31, 2000. This valuation allowance was initially recorded at December 31, 1998 and remained fully reserved at December 31, 1999, based upon management's belief that it was more likely than not that we would not be able to generate sufficient taxable income to realize the benefit of our net deferred tax assets. In reaching this conclusion, management considered both historical results and its expectations regarding future taxable income based on oil and gas pricing consistent with our long-term forecasting and anticipated levels of capital spending. As a result of the near-term recovery of oil and natural gas prices that began in the latter part of 1999 and continued throughout 2000, we were able to generate net income for 2000 and taxable income that utilized approximately $27.2 million of our net operating losses. Based on expectations at that time regarding the future and our expectations regarding future taxable income and our ability to realize the benefit of our deferred tax asset, we concluded that the valuation allowance on our net deferred tax assets was no longer necessary and at December 31, 2000 eliminated the entire valuation allowance.

Our current income tax expense in 2001 and 2000 was for alternative minimum taxes that could not be offset by our alternative minimum tax net operating losses and conversely, 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, 2002, we had net operating loss carryforwards for U.S. federal income tax purposes of $84.9 million and $4.2 million for alternative minimum tax purposes. During 2002 and 2001, we utilized approximately $16 million and $23 million, respectively, of regular and alternative minimum net operating losses to minimize our current tax position. As a result of the acquisition of Matrix and other prior ownership changes, the utilization of some of our net operating loss carryforwards is subject to limitations imposed by the Internal Revenue Code of 1986. However, we do not expect such limitations to have an effect on our ability to use these net operating loss carryforwards. Our net operating loss carryforwards are scheduled to expire as follows:

Amounts in Thousands	Income Tax	Alternative Minimum Tax
Year		
2018	$61,882	$ —
2019	21,080	3,853
2020	826	193
2021	1,073	127
2022	30	30

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 is approximately $9.9 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, 2002 and 2001 balance sheet dates. At December 31, 2002 and 2001, our deferred tax assets and liabilities were as follows:

Amounts in Thousands	December 31, 2002	2001
Deferred tax assets:		
Loss carryforwards	**$ 32,266**	$ 37,222
Tax credit carryover	**1,069**	1,403
Enhanced oil recovery credit carryforwards	**9,927**	5,280
Derivative hedging contracts	**11,822**	—
Other	**79**	—
Total deferred tax assets	**55,163**	43,905
Deferred tax liabilities:		
Property and equipment	**(76,940)**	(52,449)
Derivative hedging contracts	**—**	(8,356)
Other	**—**	(533)
Total deferred tax liabilities	**(76,940)**	(61,338)
Total net deferred tax liability	**$(21,777)**	$(17,433)

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

Amounts in Thousands	Year Ended December 31, 2002	2001	2000
Income tax provision calculated using the federal statutory income tax rate	**$24,587**	$28,481	$ 26,227
State income taxes and other	**2,327**	1,623	1,616
Change in valuation allowance	**—**	—	(95,137)
Enhanced oil recovery credits	**(3,394)**	(5,280)	—
Total income tax expense (benefit)	**$23,520**	$24,824	$(67,294)

NOTE 6. 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 Option Plan

As of December 31, 2002, we had a total of 7,345,587 shares of common stock authorized for issuance pursuant to our Stock Option Plan, of which 1,117,347 shares were available for issuance. Denbury's board of directors has authorized an additional 850,000 shares for this plan, subject to the approval of shareholders at the May 20, 2003 annual meeting. Under the terms of the plan, incentive and non-qualified options may be issued to officers, key employees and consultants. 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 as the average closing price of our common stock for the ten trading days prior to issuance. The plan is administered by the Stock Option Committee of Denbury's board of directors.

The following is a summary of our stock option activity:

	Year Ended December 31,					
	2002		2001		2000	
	Number of Options	Weighted Average Price	Number of Options	Weighted Average Price	Number of Options	Weighted Average Price
Outstanding at beginning of year	**4,616,333**	**$ 8.40**	3,802,122	$8.03	3,317,384	$8.66
Granted	**921,341**	**7.50**	1,222,141	9.00	595,635	4.11
Exercised	**(370,120)**	**4.51**	(209,600)	5.00	(40,458)	4.60
Forfeited	**(170,079)**	**10.30**	(198,330)	8.53	(70,439)	6.70
Outstanding at end of year	**4,997,475**	**$ 8.46**	4,616,333	$8.40	3,802,122	$8.03
Exercisable at end of year	**2,267,497**	**$10.26**	1,858,072	$9.49	1,310,382	$9.35
Weighted average fair value of options granted		**$ 4.17**		$5.19		$2.26

The following is a summary of stock options outstanding at December 31, 2002:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Options Outstanding at 12/31/02	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number of Options Exercisable at 12/31/02	Weighted Average Exercise Price
$3.77 - $5.50	1,549,501	6.3	$ 4.16	694,420	$ 4.24
5.51 - 8.00	1,053,500	7.7	7.00	238,859	6.75
8.01 - 11.50	1,393,734	7.8	9.24	333,478	9.46
11.51 - 14.50	566,738	3.9	13.38	566,738	13.38
14.51 - 22.25	434,002	4.8	18.38	434,002	18.38
$3.77 -$22.25	4,997,475	6.6	$ 8.46	2,267,497	$10.26

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, 2002, there are 593,272 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 at its current market value at the end of each quarter. We recognize compensation expense for the 75% company matching portion, which totaled $822,000, $666,000 and $560,000 for the years ended December 31, 2002, 2001 and 2000, respectively. This plan is administered by the Stock Purchase Plan Committee of Denbury's board of directors.

401(k) Plan

Denbury offers a 401(k) Plan to which employees may contribute tax deferred earnings subject to Internal Revenue Service limitations. Up to 3% of an employee's compensation, as defined by the plan, is matched by Denbury at 100% and an employee's contribution between 3% and 6% of compensation is matched by Denbury at 50%. Denbury's match is vested immediately. During 2002, 2001 and 2000, Denbury's matching contributions were $884,000, $670,000 and $427,000, respectively, to the 401(k) Plan.

NOTE 7. 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. We generally attempt 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. When we make an acquisition, we 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 predominately with collars, although for the recent 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) representing cash receipts and payments on our hedge settlements:

	Year Ended December 31,		
Amounts in Thousands	**2002**	**2001**	**2000**
Oil hedge contracts	**$ (598)**	$ 1,925	$(13,332)
Gas hedge contracts	**1,530**	16,729	(11,932)
Net gain (loss)	**$ 932**	$ 18,654	$(25,264)

Some of our derivative contracts require us to pay a premium which we amortize over the contract periods. This expense is included in "Amortization of derivative contracts and other non-cash hedging adjustments" in our Consolidated Statements of Operations. For the years ended December 31, 2002 and 2001, we recorded premium amortization expense of $9.7 million and $5.3 million, respectively. Also, for the year ended December 31, 2002, we reclassified $13.4 million related to our former Enron hedges (discussed below) out of accumulated other comprehensive income into income and recorded hedge ineffectiveness of $600,000 which is also included in "Amortization of derivative contracts and other non-cash hedging adjustments."

Loss on Enron Hedges

In conjunction with the acquisition of Matrix 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 since December 2001, based on the futures prices as of March 1, 2003, we would not have collected anything on the price floors relating to 2003 even if Enron had not filed bankruptcy as the current market price is above $3.75 (the floor price for 2003). We estimate 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, our 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 is that any future changes in the current market value of these assets must be reflected in the income statement and any remaining accumulated other comprehensive income at the time of the accounting change must 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 will recognize pre-tax income during 2003 of approximately $5.1 million. The three year total pre-tax net loss on the Enron hedges will be approximately $5.9 million, which approximates the differences between the amount collected and paid for the Enron portion of the Matrix price floors.

Hedging Contracts at December 31, 2002

Crude Oil Contracts:

	NYMEX Contract Prices Per Bbl					Fair Value at Dec. 31, 2002
				Collar Prices		
Type of Contract and Period	Bbls/d	Swap Price	Floor Price	Floor	Ceiling	
Collar Contracts						
Jan. 2003 - Dec. 2003	10,000	$ —	$ —	$20.00	$30.00	$(2,077)
Swap Contracts						
Jan. 2003 - Dec. 2003	2,500	24.25	—	—	—	(2,403)
Jan. 2003 - Dec. 2003	2,000	24.30	—	—	—	(1,886)
Jan. 2003 - Dec. 2003	2,000	25.70	—	—	—	(872)
Jan. 2004 - Dec. 2004	2,500	22.89	—	—	—	(415)
Jan. 2004 - Dec. 2004	4,500	23.00	—	—	—	(571)
Jan. 2004 - Dec. 2004	2,500	23.08	—	—	—	(246)

Natural Gas Contracts:

	NYMEX Contract Prices Per MMBtu					Fair Value at Dec. 31, 2002
				Collar Prices		
Type of Contract and Period	MMBtu/d	Swap Price	Floor Price	Floor	Ceiling	
Collar Contracts						
Jan. 2003 - Dec. 2003	45,000	$ —	$ —	$ 2.75	$ 4.00	$(12,866)
Jan. 2003 - Dec. 2003	25,000	—	—	2.75	4.07	(6,738)
Jan. 2004 - Dec. 2004	30,000	—	—	3.50	4.45	(3,278)
Jan. 2004 - Dec. 2004	15,000	—	—	3.00	5.87	(774)
Jan. 2004 - Dec. 2004	15,000	—	—	3.00	5.82	(808)
Jan. 2005 - Dec. 2005	15,000	—	—	3.00	5.50	(189)
Swap Contracts						
Jan. 2003 - Dec. 2003	10,000	3.905	—	—	—	(2,448)

At December 31, 2002, our derivative contracts were recorded at their fair value, which was a net liability of $35.6 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 $19.3 million at December 31, 2002, represents the deficit in the fair market value of our derivative contracts as compared to the cost of our hedges, net of income taxes, and also includes the remaining accumulated other comprehensive income of $3.1 million relating to the Enron hedges that ceased to qualify for hedge accounting treatment when Enron filed for bankruptcy. This $3.1 million relating to the former Enron hedges will be reclassified out of accumulated other comprehensive income during 2003, over the periods that the hedges would have otherwise expired. Of the

$19.3 million in accumulated other comprehensive loss as of December 31, 2002, $15.4 million relates to current hedging contracts that will expire within the next 12 months and $3.9 million relates to contracts that expire after December 31, 2003.

NOTE 8. COMMITMENTS AND CONTINGENCIES

We have operating leases for the rental of office space, office equipment, and vehicles that totaled $1.7 million, $1.6 million and $1.4 million for the years ended December 31, 2002, 2001 and 2000, respectively. At December 31, 2002, long-term commitments for these items require the following future minimum rental payments:

Amounts in Thousands	
2003	$ 1,708
2004	1,640
2005	1,764
2006	1,766
2007	1,761
Thereafter	3,022
Total lease commitments	$11,661

We have future capital expenditure obligations related to field development costs that total $13.0 million over the next five years, of which $2.3 million is required to be spent in 2003.

Long-term contracts require us to deliver CO_2 to our industrial CO_2 customers. Based upon the maximum amounts deliverable as stated in the contracts, we estimate that we may be obligated to deliver up to 387 Bcf of CO_2 to these customers over the next 18 years; however, based on the current level of deliveries, our commitment would be reduced to approximately 250 Bcf. Also, in the unforeseen circumstance that we could not deliver all of the volumes under these contracts, we could reduce our deliveries to all parties proportionately with the exception of one party, which has preferential rights under their contract. Given the size of our proven CO_2 reserves (approximately 1.6 Tcf), our current production capabilities and our predicted levels of CO_2 usage for our own tertiary flooding program, we are confident that we can meet these delivery obligations.

Denbury is subject to various possible contingencies which arise primarily from interpretation of federal and state laws and regulations affecting the oil and natural gas industry. Such contingencies include differing interpretations as to the prices at which oil and natural gas sales may be made, the prices at which royalty owners may be paid for production from their leases, environmental issues and other matters. Although management believes that it has complied with the various laws and regulations, administrative rulings and interpretations thereof, adjustments could be required as new interpretations and regulations are issued. In addition, production rates, marketing and environmental matters are subject to regulation by various federal and state agencies.

We are involved in various lawsuits, claims and regulatory proceedings incidental to our businesses. In the opinion of management, the outcome of such matters will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

NOTE 9. 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, 2002, we had two significant purchasers that each accounted for 10% or more of our oil and natural gas revenues: Hunt Refining (14%) and Genesis (11%). For the year ended December 31, 2001, four purchasers each accounted for 10% or more of our oil and natural gas revenues: Conoco (14%), Hunt Refining (13%), EOTT Energy (12%), and Dynegy (12%). For the year ended December 31, 2000, four purchasers each accounted for 10% or more of our oil and natural gas revenues: Hunt Refining (24%), Southland Refining (17%), EOTT Energy (16%), and Dynegy (10%).

Accounts Payable and Accrued Liabilities

Amounts in Thousands	December 31, 2002	2001
Accounts payable	**$25,545**	$37,718
Accrued exploration and development costs	**9,935**	16,198
Accrued interest	**6,248**	6,976
Other	**7,553**	5,606
Total	**$49,281**	$66,498

Supplemental Cash Flow Information

Amounts in Thousands	Year Ended December 31, 2002	2001	2000
Interest paid	**$24,636**	$17,451	$13,936
Income taxes paid (refunded)	**(1,304)**	2,482	275

In 2001, in connection with our acquisition of Matrix, we recorded non-cash increases to property and equipment resulting from the issuance of common stock in the amount of $59.2 million and the recording of deferred taxes in the amount of $53.1 million.

Fair Value of Financial Instruments

	December 31, 2002		2001	
Amounts in Thousands	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Senior bank debt	**$150,000**	**$150,000**	$140,870	$140,870
9% Senior Subordinated Notes due 2008	**125,000**	**129,113**	125,000	117,500
9% Series B Senior Subordinated Notes due 2008	**69,889**	**77,468**	68,899	70,500

As of December 31, 2002 and 2001, 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. We have other financial instruments consisting primarily of cash, cash equivalents, short-term receivables and payables which approximate fair value due to the nature of the instrument and the relatively short maturities.

NOTE 10. 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:

Amounts In Thousands	Year Ended December 31, 2002	2001	2000
Property acquisitions:			
Proved [1]	**$ 56,364**	$127,066	$ 50,285
Unevaluated	**4,342**	37,051	11,741
Exploration	**13,493**	11,692	6,782
Development	**81,438**	151,366	65,213
Total costs incurred [2]	**$155,637**	$327,175	$134,021

(1) Excludes deferred taxes recorded in the acquisition of Matrix of $53.1 million in 2001.
(2) Capitalized general and administrative costs that directly relate to exploration and development activities were $5.3 million, $4.1 million and $3.2 million for the years ended December 31, 2002, 2001 and 2000, respectively.

Oil and Natural Gas Operating Results

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

Amounts In Thousands	Year Ended December 31, 2002	2001	2000
Oil, natural gas and related product sales	**$274,894**	$260,398	$204,636
Gain (loss) on settlements of derivative contracts	**932**	18,654	(25,264)
Total revenues	**275,826**	279,052	179,372
Lease operating costs	**71,188**	55,049	38,676
Production taxes and marketing expenses	**11,902**	10,963	8,051
Depletion and depreciation	**90,679**	69,773	36,214
Loss on Enron related assets	**—**	25,164	—
Amortization of derivative contracts and other non-cash hedging adjustments	**(3,093)**	7,816	—
Net operating income	**105,150**	110,287	96,431
Income tax provision (benefit)	**36,563**	35,526	(67,294)
Results of operations from oil and natural gas producing activities	**$ 68,587**	$ 74,761	$163,725
Depletion and depreciation per BOE	**$ 6.98**	$ 6.01	$ 4.48

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 unless the project is scheduled in our development budget (or at least the commencement of the project in the case of longer-term multi-year projects such as waterfloods and tertiary recovery projects). In most cases our development budget is only prepared for the next year or so. We also have a corporate policy whereby proved undeveloped reserves must be economic at low to moderate commodity prices, which for 2002 and the prior two years we set at $18.50 per Bbl of oil and $2.50 per Mcf of natural gas.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. Moreover, the present values should not be construed as the current market value of our oil and natural gas reserves or the costs that would be incurred to obtain equivalent reserves. All of our reserves are located in the United States.

Estimated Quantities of Reserves

	Year Ended December 31,					
	2002		2001		2000	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)
Balance at beginning of year	**76,490**	**198,277**	70,667	100,550	51,832	50,438
Revisions of previous estimates	**(408)**	**(22,975)**	4,344	(631)	4,078	8,271
Revisions due to price changes	**3,020**	**2,660**	(7,800)	(2,745)	412	1,905
Extensions and discoveries	**2,326**	**51,819**	2,308	66,448	2,746	25,593
Improved recovery [1]	**—**	**—**	1,667	—	16,466	5,613
Production	**(6,874)**	**(36,662)**	(6,197)	(31,112)	(5,555)	(13,533)
Acquisition of minerals in place	**23,383**	**9,360**	11,501	65,767	1,182	23,209
Sales of minerals in place	**(734)**	**(1,532)**	—	—	(494)	(946)
Balance at end of year	**97,203**	**200,947**	76,490	198,277	70,667	100,550
Proved developed reserves						
Balance at beginning of year	**54,722**	**169,897**	52,353	77,358	32,767	41,635
Balance at end of year	**62,398**	**142,812**	54,722	169,897	52,353	77,358

(1) Improved recovery additions result from the application of secondary recovery methods such as waterflooding 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, adjusted for fixed and determinable escalations, 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,		
	2002	2001	2000
Oil (NYMEX)	**$31.20**	$19.84	$26.80
Natural Gas (NYMEX Henry Hub)	**4.79**	2.57	9.78

Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pre-tax cash inflows. Future income taxes were computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the associated proved oil and natural gas properties. Tax credits and net operating loss carryforwards were also considered in the future income tax calculation. Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the Standardized Measure.

Amounts In Thousands	December 31, 2002	2001	2000
Future cash inflows	**$ 3,787,077**	$1,786,884	$ 2,609,306
Future production costs	**(1,044,193)**	(655,363)	(600,195)
Future development costs	**(268,269)**	(178,546)	(95,068)
Future net cash flows before taxes	**2,474,615**	952,975	1,914,043
10% annual discount for estimated timing of cash flows	**(1,048,395)**	(378,647)	(755,074)
Discounted future net cash flows before taxes	**1,426,220**	574,328	1,158,969
Discounted future income taxes	**(397,244)**	(68,533)	(317,670)
Standardized measure of discounted future net cash flows	**$ 1,028,976**	$ 505,795	$ 841,299

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:

Amounts In Thousands	Year Ended December 31, 2002	2001	2000
Beginning of year	**$ 505,795**	$ 841,299	$448,374
Sales of oil and natural gas produced, net of production costs	**(191,803)**	(194,386)	(157,909)
Net changes in sales prices	**694,646**	(838,124)	281,181
Extensions and discoveries, less applicable future development and production costs	**151,926**	123,214	200,966
Improved recovery[1]	—	5,045	77,702
Previously estimated development costs incurred	**34,931**	64,072	20,623
Revisions of previous estimates, including revised estimates of development costs, reserves and rates of production	**(50,855)**	(13,290)	48,018
Accretion of discount	**57,433**	115,897	46,287
Acquisition of minerals in place	**160,899**	152,931	183,634
Sales of minerals in place	**(5,285)**	—	(4,403)
Net change in income taxes	**(328,711)**	249,137	(303,174)
End of year	**$1,028,976**	$ 505,795	$841,299

(1) Improved recovery additions result from the application of secondary recovery methods such as waterflooding 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 working interest basis, were estimated at approximately 1.6 Tcf at December 31, 2002 and 815 Bcf at December 31, 2001.

NOTE 11. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

As of December 31, 2002, all of our senior subordinated notes were fully and unconditionally guaranteed by Denbury Resources Inc.'s significant subsidiaries. Genesis Energy, Inc., the subsidiary that holds the 2% general partner interest in Genesis Energy, L.P., was not a guarantor of our subordinated notes at that date. The following condensed consolidating financial information for Denbury Resources Inc. and its significant subsidiaries includes the results of our equity interest in Genesis, which is recorded under the equity method by Denbury Gathering & Marketing.

Condensed Consolidating Balance Sheets

Amounts in Thousands	December 31, 2002 Denbury Resources Inc. (Parent and Issuer)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Assets				
Current assets	$111,063	$ 17,401	$ —	$128,464
Property and equipment	528,754	215,331	—	744,085
Investment in subsidiaries (equity method)	169,309	2,224	(169,309)	2,224
Other assets	16,881	3,638	—	20,519
Total assets	$826,007	$238,594	$(169,309)	$895,292
Liabilities and Stockholders' Equity				
Current liabilities	$ 87,101	$ 8,778	$ —	$ 95,879
Long-term liabilities	372,109	60,507	—	432,616
Stockholders' equity	366,797	169,309	(169,309)	366,797
Total liabilities and stockholders' equity	$826,007	$238,594	$(169,309)	$895,292

Amounts in Thousands	December 31, 2001 Denbury Resources Inc. (Parent and Issuer)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Assets				
Current assets	$ 98,182	$ 5,096	$ —	$ 103,278
Property and equipment	445,693	222,314	—	668,007
Investment in subsidiaries (equity method)	164,830	—	(164,830)	—
Other assets	15,684	3,019	—	18,703
Total assets	$ 724,389	$ 230,429	$ (164,830)	$ 789,988
Liabilities and Stockholders' Equity				
Current liabilities	$ 68,937	$ 11,001	$ —	$ 79,938
Long-term liabilities	306,284	54,598	—	360,882
Stockholders' equity	349,168	164,830	(164,830)	349,168
Total liabilities and stockholders' equity	$ 724,389	$ 230,429	$ (164,830)	$ 789,988

Condensed Consolidating Statements of Operations

Amounts in Thousands	Year Ended December 31, 2002 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

Amounts in Thousands	Year Ended December 31, 2001			
	Denbury Resources Inc. (Parent and Issuer)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 261,678	$ 23,433	$ —	$ 285,111
Expenses	181,346	22,391	—	203,737
Income before the following:	80,332	1,042	—	81,374
Equity in net earnings of subsidiaries	653	—	(653)	—
Income (loss) before income taxes	80,985	1,042	(653)	81,374
Income tax provision	24,435	389	—	24,824
Net income (loss)	$ 56,550	$ 653	$ (653)	$ 56,550

Amounts in Thousands	Year Ended December 31, 2000			
	Denbury Resources Inc. (Parent and Issuer)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 180,538	$ 1,113	$ —	$ 181,651
Expenses	106,805	(87)	—	106,718
Income before the following:	73,733	1,200	—	74,933
Equity in net earnings of subsidiaries	1,200	—	(1,200)	—
Income (loss) before income taxes	74,933	1,200	(1,200)	74,933
Income tax benefit	(67,294)	—	—	(67,294)
Net income (loss)	$ 142,227	$ 1,200	$ (1,200)	$ 142,227

Condensed Consolidating Statements of Cash Flows

Amounts in Thousands	Year Ended December 31, 2002			
	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**

Amounts in Thousands	Year Ended December 31, 2001			
	Denbury Resources Inc. (Parent and Issuer)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Cash flow from operations	$ 154,034	$ 31,013	$ —	$ 185,047
Cash flow from investing activities	(294,253)	(24,577)	—	(318,830)
Cash flow from financing activities	134,986	—	—	134,986
Net increase (decrease) in cash flow	(5,233)	6,436	—	1,203
Cash, beginning of period	22,285	8	—	22,293
Cash, end of period	$ 17,052	$ 6,444	$ —	$ 23,496

	Year Ended December 31, 2000			
Amounts in Thousands	Denbury Resources Inc. (Parent and Issuer)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Cash flow from operations	$ 98,004	$ (2,032)	$ —	$ 95,972
Cash flow from investing activities	(133,040)	—	—	(133,040)
Cash flow from financing activities	47,593	—	—	47,593
Net increase (decrease) in cash flow	12,557	(2,032)	—	10,525
Cash, beginning of period	9,728	2,040	—	11,768
Cash, end of period	$ 22,285	$ 8	$ —	$ 22,293

NOTE 12. SUBSEQUENT EVENTS (UNAUDITED)

In February 2003, we sold Laurel Field, acquired in the COHO acquisition, for $27.0 million and other consideration which included an interest in Atchafalaya Bay Field (where we already own an interest) and seismic over that area. At December 31, 2002, Laurel Field had approximately 7.4 MMBbls of proved reserves. We have also reached an agreement to sell two other fields that we acquired in the COHO acquisition, Bentonia and Glazier Fields, for approximately $2.0 million combined, and this sale is expected to close in late March. Both of these are much smaller fields with approximately 269,000 Bbls of proved reserves at December 31, 2002. The proceeds from the sale of Laurel Field were used to reduce our bank debt.

On March 17, 2003, we announced a refinancing of our 9% Senior Subordinated Notes due 2008. We sold $225 million of 7.5% Senior Subordinated Notes due 2013 and called our existing $200 million of 9% notes at 104.5% of face value. Closing on the new notes is scheduled for March 25, 2003, subject to the satisfaction of customary closing conditions, and the redemption of the old notes is expected to occur on April 16, 2003. We intend to use the remaining net proceeds from this offering to reduce bank debt. Once completed, the refinancing is expected to save us around $2.6 million per year in interest expense. Assuming completion, we estimate that we will have a charge to earnings in the second quarter of 2003 of approximately $11.25 million, net of related income taxes, from the early retirement on our currently outstanding 9% notes.

NOTE 13. UNAUDITED QUARTERLY INFORMATION

In Thousands Except Per Share Amounts	March 31	June 30	Sept. 30	Dec. 31
2002				
Revenues	**$ 55,447**	**$ 73,433**	**$ 74,524**	**$ 81,748**
Expenses	**49,924**	**53,842**	**52,906**	**58,220**
Net income	**4,546**	**13,498**	**13,459**	**15,292**
Net income per share:				
Basic	**0.09**	**0.25**	**0.25**	**0.29**
Diluted	**0.08**	**0.25**	**0.25**	**0.28**
Cash flow from operations	**12,032**	**46,572**	**44,379**	**56,617**
Cash flow used for investing activities	**(27,129)**	**(32,069)**	**(80,622)**	**(31,341)**
Cash flow provided by (used for) financing activities	**5,970**	**(8,697)**	**38,992**	**(24,260)**
2001				
Revenues	$ 79,180	$ 67,407	$ 74,318	$ 64,206
Expenses	37,960	35,484	52,178	78,115
Net income (loss)	25,969	20,111	13,948	(3,478)
Net income (loss) per share:				
Basic	0.56	0.44	0.27	(0.07)
Diluted	0.55	0.42	0.26	(0.07)
Cash flow from operations	66,089	30,886	45,097	42,975
Cash flow used for investing activities	(70,391)	(44,891)	(139,993)	(63,555)
Cash flow provided by financing activities	8,530	10,820	95,297	20,339

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. Denbury de-listed from the Toronto Stock Exchange effective April 15, 2002.

As of February 1, 2003, to the best of our knowledge, the outstanding shares of Denbury's common stock were held by approximately 770 holders of record; however, we estimate the number of beneficial owners of Denbury's common stock to be in excess of 1,500.

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.

	NYSE	
	High	Low
2002		
First quarter	**$ 8.50**	**$6.20**
Second quarter	**10.42**	**7.91**
Third quarter	**10.35**	**7.80**
Fourth quarter	**11.97**	**9.45**
2002 annual	**$11.97**	**$6.20**
2001		
First quarter	$ 12.00	$ 7.90
Second quarter	12.30	7.30
Third quarter	9.75	7.50
Fourth quarter	8.81	6.00
2001 annual	$ 12.30	$ 6.00

CORPORATE INFORMATION

Board of Directors

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

David Bonderman
Principal
Texas Pacific Group
Fort Worth, Texas

David I. Heather
President
The Scotia Group
Dallas, Texas

David B. Miller
Senior Managing Director
EnCap Investments L.L.C.
Dallas, Texas

William S. Price, III
Principal
Texas Pacific Group
San Francisco, California

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

Jeffrey Smith
Principal
Texas Pacific Group
San Francisco, California

Wieland F. Wettstein
Executive V.P.
Finex Financial
Corporation, Ltd.
Calgary, Alberta

Carrie Wheeler
Principal
Texas Pacific Group
San Francisco, California

figure 30: Carrie Wheeler, Board of Directors

Officers

Gareth Roberts
President & C.E.O.

Tracy Evans
Senior Vice President,
Reservoir Engineering

Phil Rykhoek
Senior Vice President
and Chief Financial Officer

Mark Worthey
Senior Vice President,
Operations

Mark Allen
Vice President and
Chief Accounting Officer

Ron Gramling
Vice President, Marketing

Ray Dubuisson
Vice President, Land

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Register and Transfer Agent
American Stock Transfer
and Trust Company
New York, NY

Legal Counsel
Jenkens & Gilchrist

Bankers
Bank One (Agent)

Auditors
Deloitte & Touche

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 will send shareholders a copy of our 2002 Annual Report on Form 10-K filed with the SEC, without charge, upon written request to Laurie Underwood at the Company's headquarters. This report can also be accessed at our website, www.denbury.com

Annual Meeting
The annual meeting of stockholders will be held on May 20, 2003, at 3:00 P.M., local time, at the Denbury offices located at:
5100 Tennyson Parkway
Suite 3000
Plano, Texas 75024.
All stockholders are encouraged to attend, but if unable should complete and return the proxy card.

Denbury Resources Inc.

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