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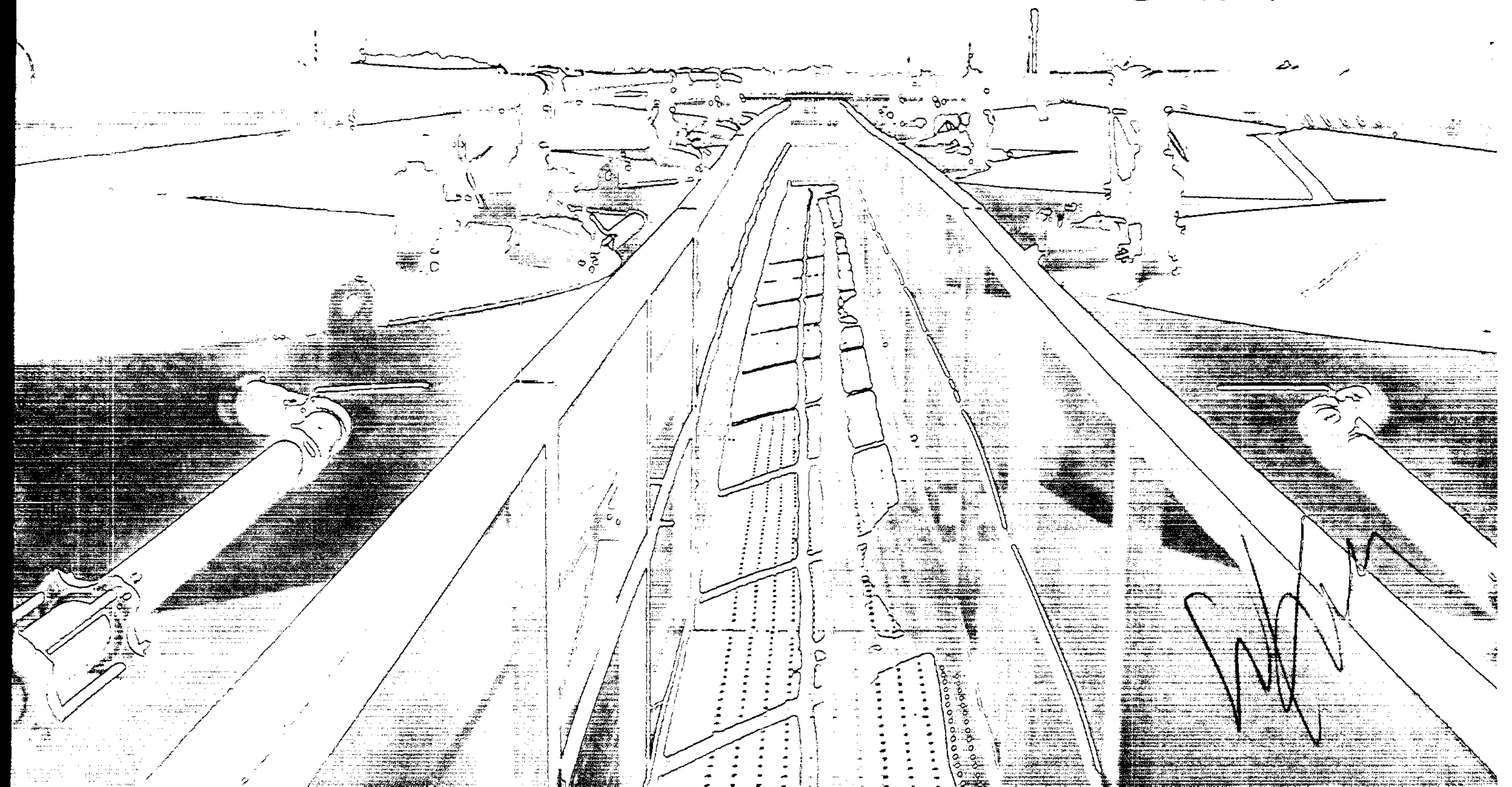
BRIGHAM
Exploration Company

2002 ANNUAL REPORT



BRIGHAM
Exploration Company

CORPORATE OVERVIEW

STRATEGY

Brigham Exploration Company's strategy is to achieve superior growth in shareholder value by **applying 3-D seismic** and other advanced technologies **to reduce the risks and finding costs in drilling for oil and natural gas reserves.**

ASSETS

Brigham's principal assets include: (1) its **experienced technical staff,** including ten geologists and geophysicists, (2) its **knowledge base** derived from its 12 year track record of successful 3-D exploration, including the drilling of over 550 3-D delineated wells in its 8,854 square mile inventory of 3-D seismic data, (3) its **recent field discoveries,** which provide a multi-year developmental drilling inventory to compliment its large 3-D delineated exploration inventory, and (4) its **proved reserve base of 121 Bcfe** at year-end 2002 that is 82% natural gas and 46% proved developed.

CORE PROVINCES

Brigham focuses its activity in established producing trends where 3-D technology may be effectively applied to generate large reserve discoveries, high production rates and high rates of return. Brigham's exploration and development activities are concentrated in three core onshore provinces: (1) West Texas, (2) the Anadarko Basin of western Oklahoma and the Texas Panhandle, and (3) the Texas Gulf Coast.

1

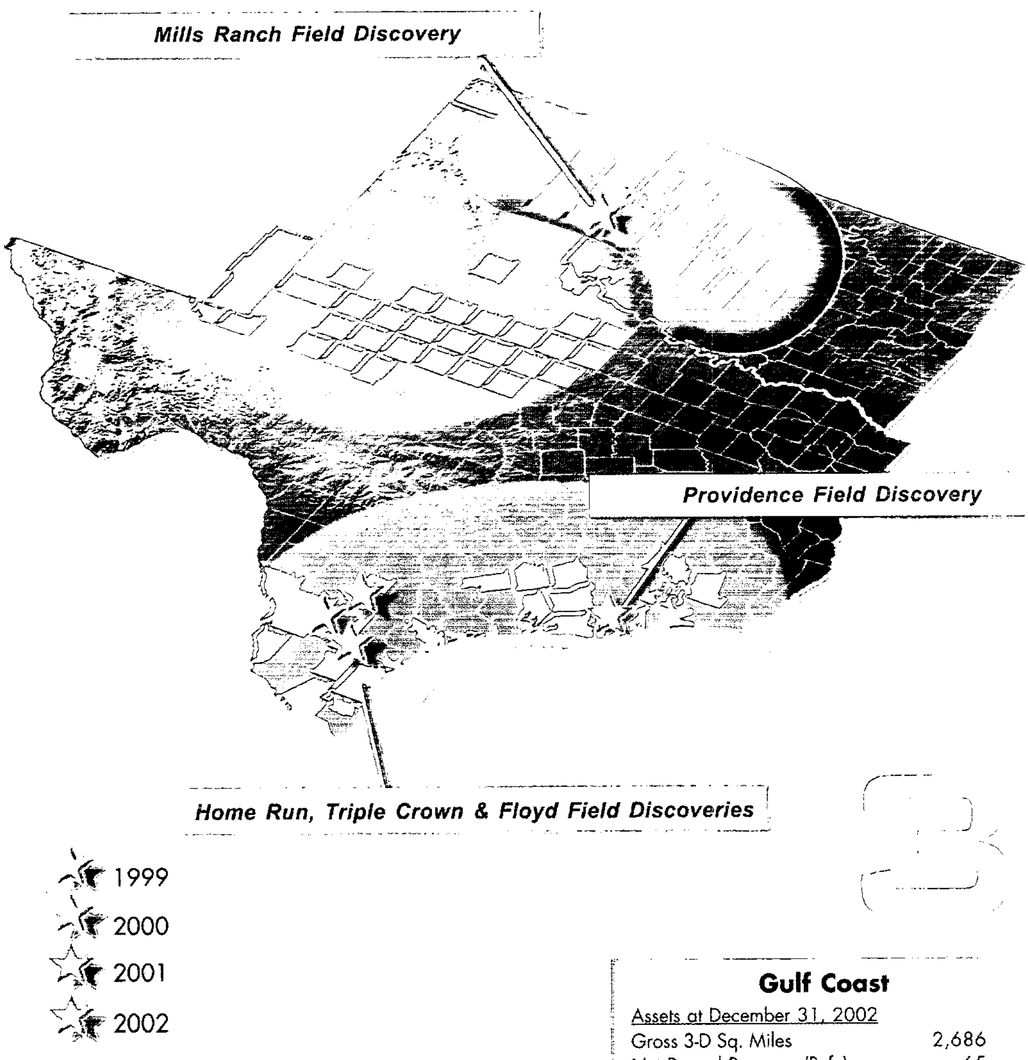
West Texas & Other

Assets at December 31, 2002	
Gross 3-D Sq. Miles	3,971
Net Proved Reserves (Bcfe)	10
Percent Gas	17%
PV10% Value ($MM)	$24
Three Year Results	
Wells Drilled/Completion Rate	13/85%
Avg. Drilling Finding Cost ($/Mcfe)	$0.78

2

Anadarko Basin

Assets at December 31, 2002	
Gross 3-D Sq. Miles	2,197
Net Proved Reserves (Bcfe)	46
Percent Gas	94%
PV10% Value ($MM)	$102
Three Year Results	
Wells Drilled/Completion Rate	31/84%
Avg. Drilling Finding Cost ($/Mcfe)	$0.96



3

Gulf Coast

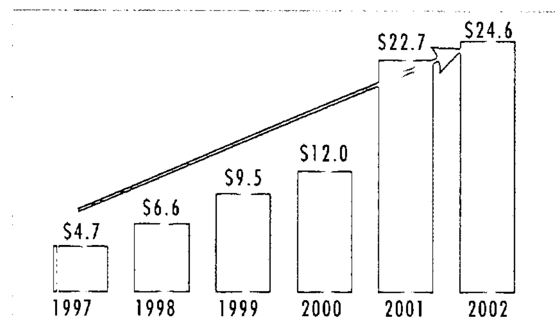
Assets at December 31, 2002	
Gross 3-D Sq. Miles	2,686
Net Proved Reserves (Bcfe)	65
Percent Gas	84%
PV10% Value ($MM)	$181
Three Year Results	
Wells Drilled/Completion Rate	40/90%
Avg. Drilling Finding Cost ($/Mcfe)	$0.98

Total Company

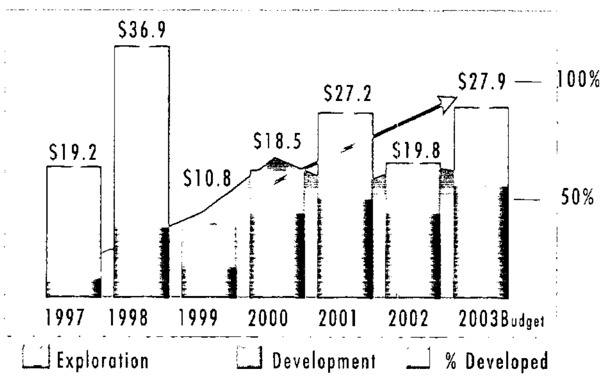
Assets at December 31, 2002	
Gross 3-D Sq. Miles	8,854
Net Proved Reserves (Bcfe)	121
Percent Gas	82%
PV10% Value ($MM)	$307
Three Year Results	
Wells Drilled/Completion Rate	84/87%
Avg. Drilling Finding Cost ($/Mcfe)	$0.96

ENHANCED CAPITAL RECYCLING

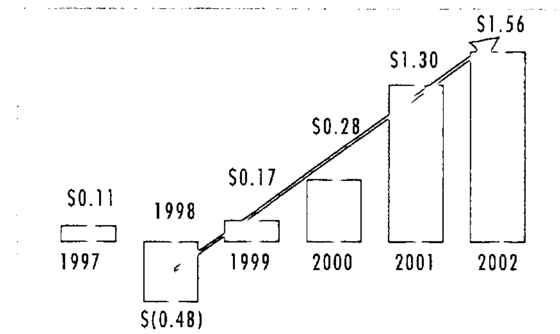
GROWING CASH FLOW - EBITDA(1) (Millions)



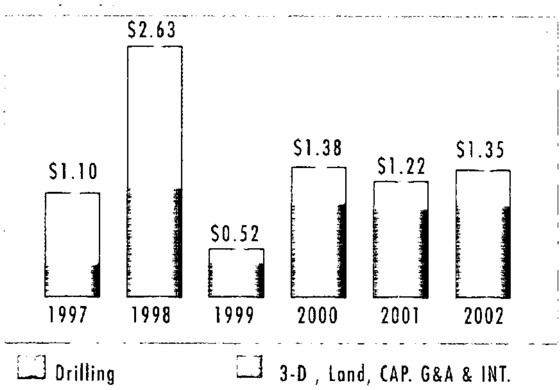
INCREASING DRILLING INVESTMENTS (Millions)



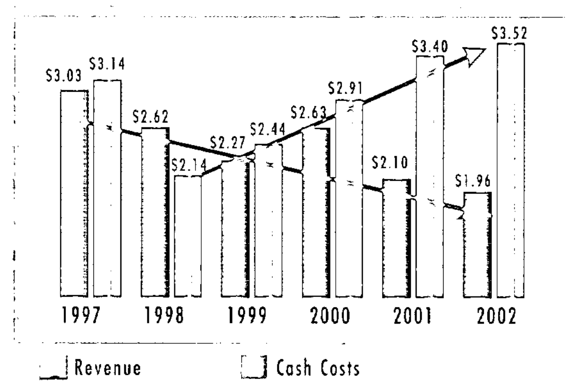
EXPANDING DISCRETIONARY CASH FLOW(1) (Per Mcfe)



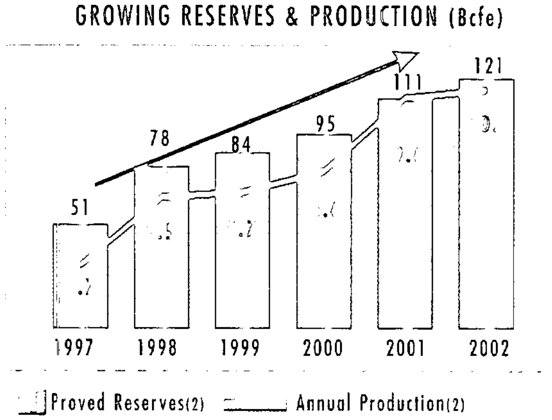
LOW ALL SOURCES FINDING COSTS (Per Mcfe)



IMPROVING REALIZATIONS & DECLINING CASH COSTS(1) (Per Mcfe)



GROWING RESERVES & PRODUCTION (Bcfe)



(1) See reconciliation of non-GAAP financial measures on page 11.
(2) Excludes purchase in 1997 and sale in 1999 of Chitwood/Red Deer Creek properties.

LETTER TO SHAREHOLDERS

Ben M. "Bud" Brigham

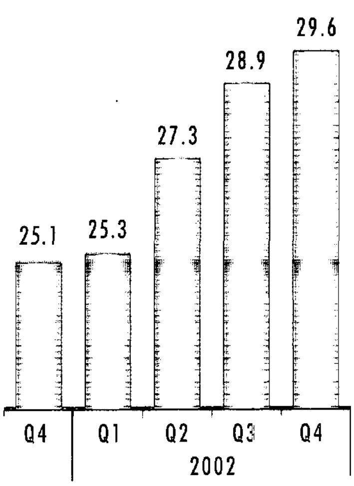
It is my pleasure to report to our shareholders on our accomplishments during 2002. It was a year of steadily rising commodity prices, which combined with our operational success and the resulting expansion of our cash flow enabled us to accelerate our drilling program late in the year. This drilling acceleration generated significant new discoveries for our company, the most important of which was our Floyd fault block discovery in the Vicksburg. We're benefiting from the powerful combination of high commodity prices, our deep and high quality inventory of drilling locations, our associated drilling successes and our expanding financial capabilities, all of which position us for a very exciting 2003.

Currently, BEXP is enjoying a win/win environment! The industry's restrained level of drilling activity is keeping service costs down, while we're selling natural gas for approximately $5.00/Mcfe. This is a remarkable and historically unique operating environment for successful natural gas drillers such as Brigham Exploration. In this environment we're differentiated, more than ever, by our multi-year predominantly natural gas prospect inventory, our low "all sources" finding costs and our uncommonly low operating costs. Combining these factors with the currently high commodity prices generates substantially expanded margins and dramatic program rates of returns.

As CEO, I believe that our ability to compound value in this environment is very much under appreciated by the market. Furthermore, our enhanced financial flexibility, by virtue of our growing cash flow and our recent financing transactions, provides us with the ability to further opportunistically accelerate our 2003 drilling activity at a uniquely optimal time for our company.

Before we look forward and tell you where we're headed, we should **look back to see where we've been**. Despite low commodity prices in early 2002, and an initial budget that provided for a 40% reduction in exploration and development expenditures from the prior year, Brigham Exploration achieved record reserves, production volumes, revenue, and EBITDA[1] in 2002 – clearly a function of our high quality inventory of drilling prospects.

Average Daily Production (MMcfe)



More specifically, **in 2002 our growth included**:

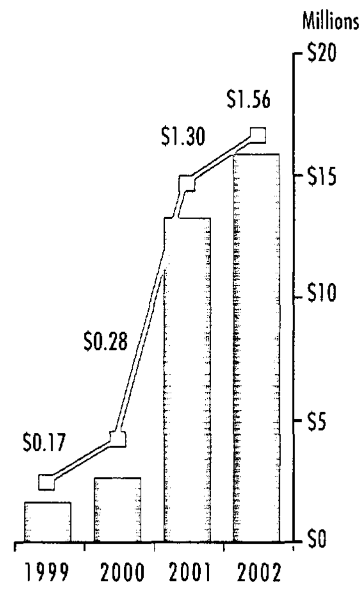
- 206% Reserve Replacement and 9% Reserve Growth to a Record 121 Bcfe.
- 4% Increase in Avg. Daily Production Volumes to a Record 27.8 MMcfe, with Q4 2002 Avg. Daily Production up 18% over Q4 2001 to a Record 29.6 MMcfe.
- 9% Increase in Revenues to a Record $35.2 million.
- 9% Increase in EBITDA[1] to a Record $24.6 million.

[1] See reconciliation of non-GAAP financial measures on page 11.

We have grown this company organically every year since inception in 1990, but, more importantly, we are achieving value added growth for our shareholders:

- Low Finding Costs - Our 2002 "all sources" finding cost of $1.35/Mcfe was consistent with our 3 year average of $1.31/Mcfe and our 7 year average of $1.34/Mcfe.
- Low Operating Costs – Our low $0.38/Mcfe 2002 LOE and our 28% reduction in cash interest expense/Mcfe contributed to a record low discretionary cash cost of $1.96/Mcfe.
- Expanding Margins - We realized our 4th consecutive increase in our discretionary cash margin to 44% in 2002, with another increase expected for 2003.
- Outstanding Returns - Our estimated unlevered program rate of return since 2000 of 47%[1], inclusive of 100% of CAPEX and G&A.

Discretionary Cash Flow [1]

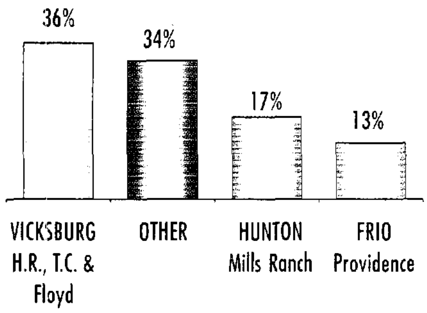


In addition to the value added growth achieved, **the following 2002 accomplishments should positively impact our growth in 2003 and beyond**:

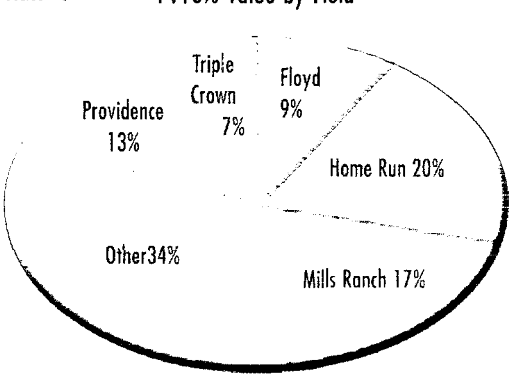
- <u>Two Successful Financial Transactions</u> reduced debt leverage by raising approximately $20 million in equity securities, reduced fully diluted shares and provided additional capital to further accelerate our drilling program.
- <u>Continued Success in the Development of Prior Field Discoveries</u> at Home Run, Mills Ranch, Triple Crown and Providence Fields.
- <u>Two New Drilling Discoveries</u> in Potentially Substantial Fields, Floyd and Dinn Ranch; Continuing our Growth in our Developmental Drilling Inventory.

Regarding the last point, **BEXP has now generated at least one significant field discovery in each of the last four years.** We discovered Home Run in 1999, Mills Ranch in 2000, and both Triple Crown and Providence in 2001. In 2002, the company made a significant discovery with our successful test of the Floyd fault block, one of several fault blocks adjacent to our Home Run and Triple Crown Fields. Brigham also participated in the drilling of two wells in the Dinn Ranch Field which, given our reversionary interest, should impact our production volumes during the second half of 2003. These fields provide BEXP shareholders with substantial value beyond our proved reserve value. Our 2002 discoveries added to what was already a multi-year developmental inventory, complementing our exploration inventory that continues to generate significant field discoveries, low finding costs and high rates of return.

Reserve PV10% Value Distribution



PV10% Value by Field



[1] See reconciliation of non-GAAP financial measures on pages 11 and 12.

These field discoveries are just one indication of the quality and depth of our prospect inventory. **We continue to successfully "Harvest the Sweet Spots", in our five focus plays:**

BEXP FOCUS & EXPERIENCE	+	DOMINANT KNOWLEDGE BASE	=	HIGH SUCCESS RATES	+	LOW FINDING COSTS
5 Focus Plays		3-D Seismic Square Miles		Recent Compl./Attempts		Proved Developed Drilling $/Mcfe
Gulf Coast						
Frio		1,088		10/11		$0.89
Vicksburg		179		13/13		$1.55
Vicksburg[2]		179		9/9		$1.34
Anadarko						
Springer		629		9/13		$1.03
Hunton		716		2/2		$0.58
West Texas						
Horseshoe Atoll		778		9/9		$0.51
Total or Average		3,390		43/48		$0.98

Over the last several years we've allocated more than 90% of our drilling expenditures to these five focus plays. As a result, inclusive of all capital expenditures, both drilling and non-drilling, and 100% of G&A expenditures, both capitalized and expensed, **we estimate our unlevered program rate of return over the last three years at approximately 47%[1]**. This calculation is based on actual costs for each program year, realized cash flow to date and forecasted cash flow based on flat pricing ($4/Mcf gas and $25/barrel oil) and production volumes taken from our third party reserve report. Furthermore, as we accelerate our drilling schedule and spread our fixed costs over a larger base of drilling activity, we have the opportunity to enhance what we consider to be outstanding program returns. As an indication of this opportunity, over the same three year period, based on drilling capital alone, our program rate of return is 119%[1]. The difference in these two percentages gives you a sense of the opportunity that the company has in front of it, and why we are so excited to be ramping up our drilling expenditures in this low service cost, high commodity price environment. In that regard, we are currently budgeting to increase our 2003 exploration and development spending by approximately 50% over 2002 spending. To the extent commodity prices remain at current levels throughout the second quarter, you could see us further increase our spending in the second half of the year.

(1) See reconciliation of non-GAAP financial measures on page 12.
(2) Excluding three early wells with completion problems prior to changed operational procedures.

Importantly, we again made progress in reducing our debt leverage, in part through our drill bit driven growth in reserves and cash flow, but also by seizing or creating transactional opportunities to improve our capital structure. We reduced our debt/Mcfe from $1.13 in 1999 to $0.55 in 2002. We expect further progress in this area in 2003. While our drilling program should continue to grow our net asset value (NAV) per share, we will continue to exploit opportunities to cost effectively reduce our debt, optimize our assets and enhance our growth in shareholder value.

We believe that Brigham Exploration, as a proven successful exploration company, particularly given our recent field discoveries and the associated probable and possible reserves, should trade at a premium to net asset value. The fact that we are currently trading at a discount to NAV represents an opportunity for investors. We also believe the market is not fully aware of our accomplishments, and we plan to work very hard in 2003 to "get the word out".

Looking forward to 2003, the following are key elements of our strategy:

- **First, we will remain focused**. Approximately 90% of our 2003 drilling expenditures are allocated to our five focus plays, in which we've recently completed 43 wells in 48 attempts.

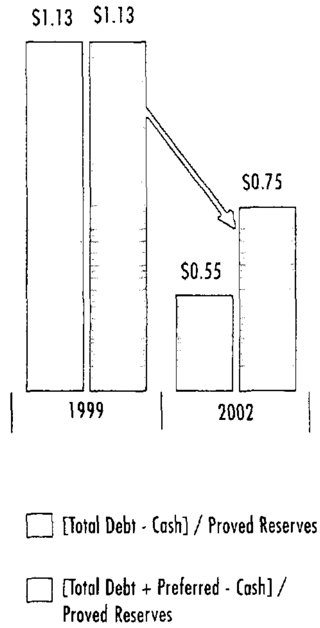
- **Second, we are accelerating our drilling program**. Our 2003 budgeted exploration and development expenditures are up almost 50% relative to 2002.

    a) We are increasing our expenditures allocated to the development of our Home Run, Triple Crown, Floyd, Providence, Mills Ranch and Dinn Ranch discoveries. Approximately 60% of our $28 million drilling budget is allocated to these economically attractive, but more predictable drilling opportunities;

    b) We are also increasing our drilling expenditures in our high potential exploration inventory. Approximately 40% of our 2003 budget is directed towards 3-D delineated exploration opportunities in our five focus plays. Our drilling in these five plays has driven our high recent success rates and low finding costs. Further, this drilling has provided at least one significant discovery in each of the last four years.

- **Third, we will continue our progress in improving cash flow margins and return on invested capital** by controlling costs while growing reserves, production volumes and cash flows.

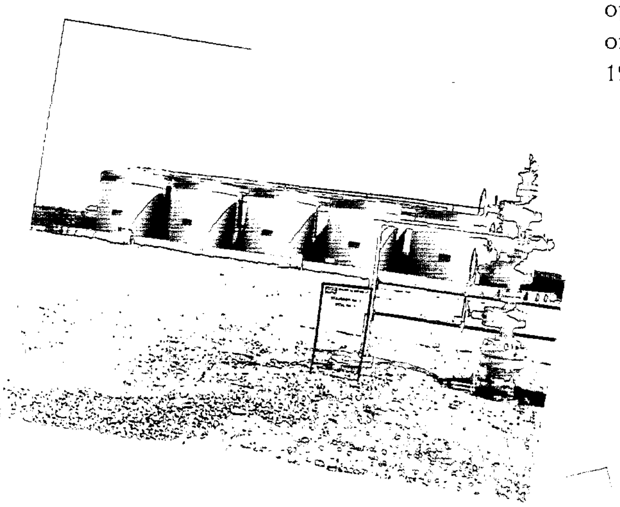
Lower Debt per Mcfe of Reserves



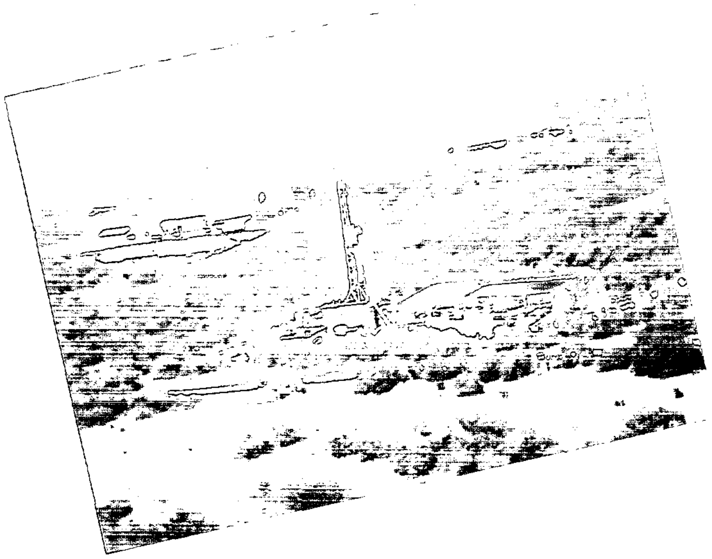
In closing, those who follow us know that the strategies outlined above are not new. On the contrary, they were communicated in my last shareholder letter, and they're essentially the same strategies we've followed for four years now. In fact, our business model is fundamentally the same as it was at our inception in 1990. Our mission remains as follows:

"Brigham Exploration utilizes state-of-the-art 3-D seismic imaging technology to cost effectively find and develop oil and gas reserves and thus grow shareholder value."

In pursuing this mission, our business has evolved very positively in recent years. Consider some of these evolutions: from shooting 3-D seismic and drilling in 28 plays around the country in the early 1990's to our focus in five proven 3-D plays in the Gulf Coast, Anadarko Basin and West Texas where we're a dominant competitor; from a pure exploration company in the early to mid 1990's to a company with five substantial fields under active development; from a non-operator of its drilling projects in the early 1990's to a company that operated more than 90% of its net wells in 2002; from a company growing organically from scratch by capturing value with 3-D seismic in the early 1990s to a company with 121 Bcfe of organically grown proven reserves, substantial probable and possible reserves, expanding cash flows and very attractive program rates of return.



I am very proud of our achievements in 2002, and just as importantly, I'm very excited about what they position us to accomplish in 2003. **These accomplishments are the product of the hard work and perseverance of our dedicated employees and loyal business partners. To each of them, and to our friends and fellow shareholders, I say "THANK YOU."** You've set the stage for what should be an exciting and rewarding 2003 for our shareholders.



Ben M. Brigham
Chairman of the Board
President and Chief Executive Officer
April 29, 2003

VICKSBURG TREND

Since 1999, our exploration efforts in the Vicksburg trend have been focused in our Diablo Project located in Brooks County in South Texas. In this area we own, along with a major integrated oil company participant, 10,000 gross and net acres of leasehold and 54 square miles of proprietary 3-D seismic data. Through year end 2002 we had completed 13 wells in 13 attempts in the Vicksburg and generated three significant field discoveries at Home Run, Triple Crown and in 2002 with our successful Floyd fault block test. Excluding three of our early completions that experienced operational problems prior to substantially changing our drilling and completion design, we've completed ten wells in ten attempts in the project at an average drilling finding cost for proved developed reserves of approximately $1.34 Mcfe.

We believe that we have a substantial inventory of proved undeveloped and non-proved Vicksburg drilling locations in our Home Run Field, Triple Crown Field, Floyd Fault Block Field, and the other adjacent fault blocks, totaling over $100 million in potential net drilling investments for our company. In 2002,we invested approximately $7.0 million to drill and complete four wells in our Diablo Project, and we estimate our 2003 drilling expenditures in the Vicksburg at approximately $9.2 million. Below are the Vicksburg wells that were spud during 2002.

Initial Daily Production Rates

Wells	Month Started Producing to Sales	Natural Gas (MMcfd)	Condensate (Bblsd)	Equivalent (MMcfed)	BEXP's NRI	Production to BEXP (MMcfed)
Palmer #5R	09/2002	9.0	520	12.1	26%	3.2
Palmer #3ST	10/2002	5.6	240	7.0	29%	2.0
Palmer #6	03/2003	12.2	550	15.5	29%	4.5
Sullivan #8	03/2003	9.2	580	12.7	25%	3.2

Home Run Field & Triple Crown Field Development

We have completed 12 consecutive wells in the Home Run and Triple Crown Fields, which were discovered in 1999 and 2001, respectively. During 2002 we drilled and completed three wells in the Home Run Field.

We have 13 proved undeveloped locations in the Home Run and Triple Crown Fields, and we believe that the fields could require up to 35 additional wells for full development.

Floyd Fault Block Vicksburg Discovery

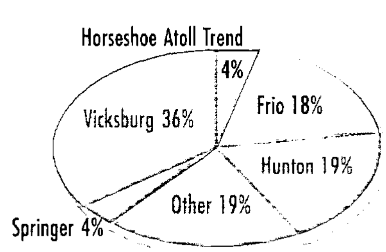
In 2002, we added to our exploration success in the Vicksburg when we drilled the Sullivan #8 and made our Floyd fault block discovery. This discovery proves up reserves in one of several fault blocks adjacent to our Home Run and Triple Crown Fields. The Sullivan #8 encountered approximately 172 feet of apparent net pay in several Lower Vicksburg pay intervals at depths between 12,900 and 13,650 feet.

2002 Statistics

- *Drilling CAPEX: $19.8 million*
- *Total CAPEX : $27.7 million*
- *Reserves Added: 20.6 Bcfe (1)*
- *All-Sources Finding Cost: $1.35 per Mcfe*
- *Average Daily Production: 27.8 MMcfe*

(1) Total reserve additions include extensions, discoveries and revisions of previous estimates.

PV10% by Focus Play

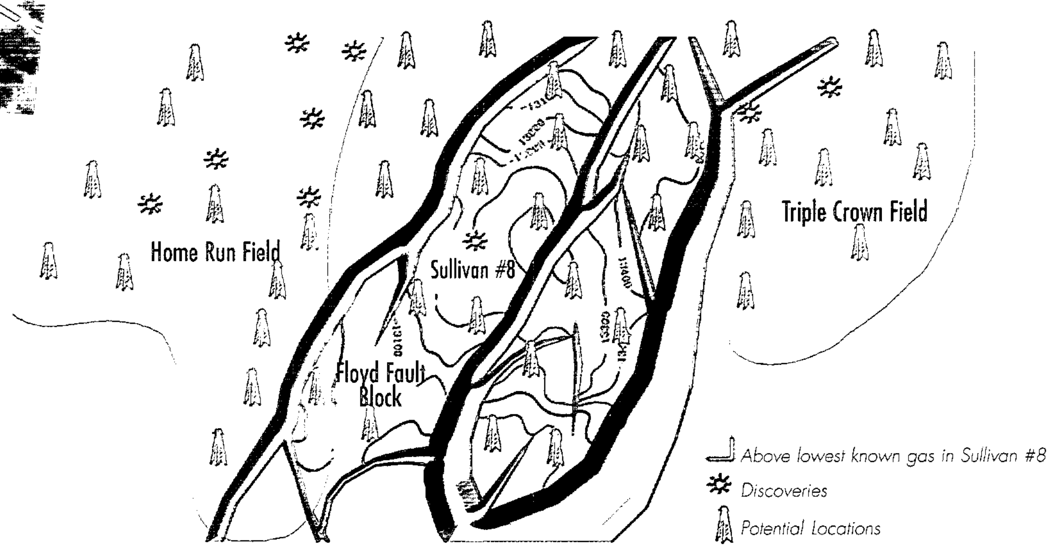


OPERATIONAL HIGHLIGHTS

Rowan Rig # 29 drilling the Palmer #5R in the Home Run Field.

The Sullivan #8 began producing to sales in March 2003 at a rate of approximately 9.2 MMcf of natural gas and 580 barrels of condensate per day (12.7 MMcfed), or approximately 3.2 MMcfed net to our 25% revenue interest, with a flowing tubing pressure of approximately 8,900 psi. The current production rate is limited by the production facilities, and we expect the operator of the well to expand the facilities in order to produce the well at higher rates.

We estimate that the Floyd fault block will require up to nine additional wells for full development, four of which are proved undeveloped. We expect to spud our first development well in the second quarter of 2003 and expect to drill up to three additional developmental wells in 2003.



Note - Northern portion of fields not illustrated.

Floyd Highlights

- *172' net pay - roughly triple the net pay of typical Home Run or Triple Crown Field well*
- *Entire fault block is above lowest known gas*
- *Portion of adjacent fault block is also above lowest known gas*
- *Impacts up to 24 potential locations*
- *Sullivan #8 flowing tubing pressure is approximately 4,000 psi higher than typical Home Run Field wells indicating the high deliverability of the Floyd fault block reservoirs*

Adjacent Fault Blocks to Home Run and Triple Crown

We also anticipate testing at least one of the other adjacent fault blocks during 2003. One of these fault blocks, Floyd East, is immediately adjacent to our Floyd Fault Block discovery. We believe that a portion of the Vicksburg sands in the Floyd East fault block are juxtaposed to the pay intervals found in the Sullivan #8. Given the probable juxtaposition and the proximity of the potential Vicksburg reservoirs, up to 15 additional locations in this and other immediately adjacent fault blocks were also positively impacted by the Floyd discovery.

Further, other fault blocks on this large, approximately 3,600 acre structure (encompassing Home Run, Triple Crown, Floyd and the intermediate fault blocks), provide the company with ten additional potential drilling locations. Therefore, in addition to the nine potential locations in the Floyd Fault block, there may be as many as 25 potential drilling locations in the other adjacent fault blocks. We expect to encounter all of these intermediate fault blocks structurally high to the adjacent Triple Crown Field, and structurally low to the adjacent Home Run Field, providing us with significant probable and possible reserve potential. In total, Brigham estimates that the entire complex (Home Run, Triple Crown, Floyd & the adjacent fault blocks) could provide up to 75 potential additional drilling locations.

FRIO TREND

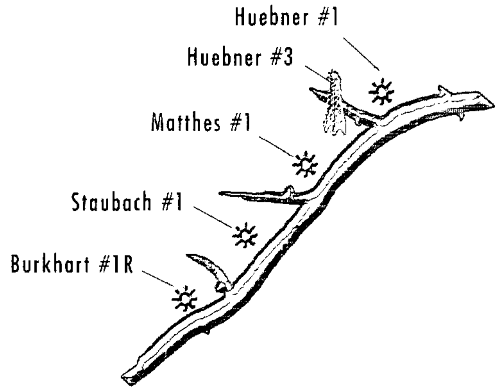
Providence Frio Field Development

We discovered the Providence Field during the fourth quarter of 2001, when we drilled and completed the Staubach #1 well. We have now successfully completed five wells in the Providence Field.

We are currently completing the Huebner #3, our fifth Providence Field well, with a 40% working interest. This well, like the recently completed Matthes #1, has two pay intervals. We expect initial production to sales in May.

Most of our production from the Providence Field in 2002 came from the first two wells drilled, the Staubach #1 and the Burkhart #1R. Gross production from the Providence Field averaged approximately 22 MMcfed during 2002. With the addition of the Huebner #1, average daily production from the Providence Field during the fourth quarter 2002 was approximately 38 MMcfed. In March 2003, we had four Providence Field wells on line producing approximately 50 MMcfed, or 13 MMcfed net to our revenue interest, with initial production from our fifth well anticipated during May.

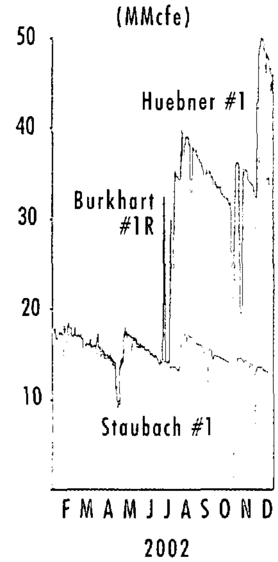
Providence Field Discovery



Providence Field Wells	Natural Gas (MMcfd)	Oil (Bblsd)	Equivalent (MMcfed)	BEXP's NRI Pre/Post Payout	Initial Production Net to BEXP (MMcfed)	Months to Payout
Staubach #1	5.0	2,000	17.0	32%/27%	5.4	3
Burkhart #1R	10.0	1,700	20.2	31%/22%	6.3	3
Huebner #1	6.1	2,230	19.5	25%/25%	4.9	3
Matthes #1[(1)]	7.7	2,518	22.8	32%/28%	7.3	2

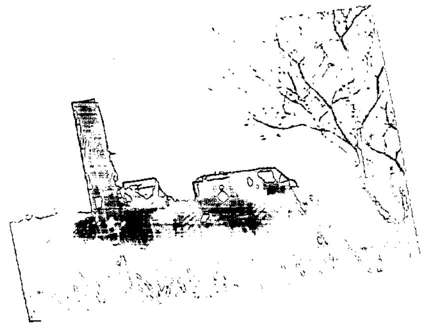
[(1)] *The Matthes #1 encountered two pay intervals, unlike the one pay interval found in each of the three previously drilled wells.*

Providence Field Daily Production



General Patton Project

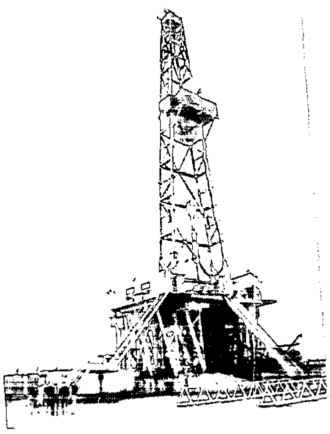
In early 2003, we added to our 3-D seismic inventory when we acquired 84 square miles of new proprietary seismic data along the same trend that has provided most of our recent Frio discoveries, including the prolific Providence Field. We sold a 50% working interest in the project, which is named General Patton, to a participant on a promoted basis. As a result, we paid 33.3% of the seismic and pre-seismic land costs for our 50% working interest in the project, while also retaining operations. Our staff recently began interpreting the data and defining drilling prospects and we hope to commence our drilling program here during the second half of 2003. The company is assembling additional 3- D projects targeting the highly prolific Frio objective.



Water buggy and buggy mounted drill rig drilling shot holes on Brigham operated General Patton 3-D seismic project.

HUNTON TREND

Mills Ranch Field



Brigham operated drilling rig on Mills Ranch Field location.

The discovery well for the Mills Ranch Field, the Mills Ranch #1, was completed and producing in January 2001 at approximately 9.5 MMcf of natural gas and 90 barrels of condensate per day. The Mills Ranch #1 paid out its drilling and completion costs during its first year of production, and at year-end 2002 had produced 3.2 Bcfe and was producing approximately 3.2 MMcfed.

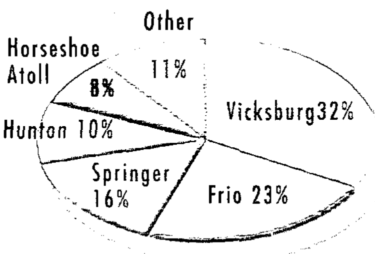
In December of 2002, we began completing the first offset to the Mills Ranch Field discovery well. We retained a 64% working interest in the Mills Ranch #2, which encountered the basal Hunton porosity zone approximately 400 feet high to the comparable zone in the discovery well. After running production casing to a depth of approximately 23,900 feet, we perforated and stimulated the lower Hunton intervals. The well began producing at an initial rate of approximately 6.7 MMcf of natural gas per day with associated condensate. The upper intervals were then stimulated and commingled into the producing stream at a recent production rate of approximately 2.0 MMcfed. Given what we have learned about the remaining reserve potential of the field, we plan to drill at least one additional development well in the Mills Ranch Field in 2003. We expect to operate and retain a 64% working interest in this well.

In addition to our development activity in the Mills Ranch Field, we continue to acquire acreage over our 3-D delineated prospects in the Hunton Trend. In 2003 we expect to spud several of these tests, including an extension well on the east side of the Mills Ranch structure, and at least one high risk but high reserve potential exploration test.

2003 DRILLING PROGRAM

Our total capital-spending budget for 2003 is $39.3 million. The majority of our planned 2003 expenditures will be directed toward drilling our prospect inventory in a continued effort to focus resources on our primary objective of growing production volumes and cash flow. To capitalize on our deep inventory of exploration and developmental locations, we have budgeted a 41% increase in our 2003 drilling capital relative to 2002. We expect to spend approximately $27.9 million to drill 41 wells with an average working interest of 36%. Capitalizing on our prior exploration successes, approximately 60% of our total 2003 drilling expenditures are dedicated to development drilling.

2003 Budgeted Drilling CAPEX by Play



For 2003, we have budgeted to spend $17.7 million to drill 17 wells in our Texas Gulf Coast province. Approximately 53% of these capital expenditures are budgeted for development drilling and will focus on the development of our Home Run, Triple Crown and Floyd Fault Block Field discoveries in the Vicksburg and the development of our Providence Field in the Frio. The remainder will be allocated to exploration drilling which includes the testing of the high reserve potential fault blocks adjacent to our Home Run, Triple Crown and Floyd Fault Block Fields and the continued drilling of our 3-D delineated exploration inventory in the Frio trend.

In our Anadarko Basin province we intend to continue to focus our drilling activity on our 3-D delineated exploration and development inventory in the Springer and Hunton trends. For 2003, we expect to spend approximately $7.6 million to drill 17 wells. Approximately 76% of these capital expenditures are budgeted for development drilling, with the remainder allocated to exploration drilling.

In our West Texas province we intend to continue to focus our drilling activities on our 3-D delineated exploration inventory in the Canyon Reef and Fusselman formations of the Horseshoe Atoll trend. We expect to spend approximately $2.6 million to drill seven wells. Approximately 48% of these capital expenditures are budgeted for development drilling, with the remainder allocated to exploration drilling.

Reconciliation of non-GAAP Financial Measures

To fully assess Brigham's operating results, management believes that, although not prescribed under generally accepted accounting principals ("GAAP"), discretionary cash flow and EBITDA are appropriate measures of the Company's ability to satisfy capital expenditure obligations and working capital requirements. Discretionary cash flow and EBITDA are non-GAAP financial measures as that term is defined under SEC rules. Brigham's discretionary cash flow and EBITDA should not be considered in isolation or as a substitute for other financial measurements prepared in accordance with GAAP or as a measure of the Company's profitability or liquidity. As discretionary cash flow and EBITDA exclude some, but not all, items that affect net income and may vary among companies, the discretionary cash flow and EBITDA presented below may not be comparable to similarly titled measures of other companies. Management believes that operating income (loss), calculated in accordance with GAAP, is the most directly comparable measure to discretionary cash flow and EBITDA.

Discretionary cash flow is defined as operating income (loss) plus depletion, depreciation and amortization expense, interest income, non-cash expenses, cash gains (losses) on the settlement of non-hedge derivatives and cash portion of other income (expense) less capitalized general and administrative cost and cash interest. The following table provides a reconciliation of discretionary cash flow to operating income (loss) for the periods presented.

	1997	1998	1999	2000	2001	2002
Operating income (loss)	$1,114	$(28,699)	$251	$3,647	$10,025	$9,435
Depletion, depreciation and amortization	3,437	9,268	9,077	8,820	13,888	15,034
Interest income	145	136	176	108	264	119
Other non-cash expenses	0	25,926	0	0	0	596
Cash portion of other income (expense)	0	0	(48)	0	0	(14)
Cash gain (loss) on settlements of non-hedge derivitives	0	0	0	(620)	(1,492)	(559)
Capitalized general and administrative cost	(3,141)	(4,256)	(3,556)	(3,406)	(3,902)	(4,220)
Cash interest	(1,190)	(5,601)	(4,856)	(6,696)	(6,316)	(4,803)
Discretionary cash flow	$365	$(3,226)	$1,044	$1,853	$12,467	$15,588

EBITDA is defined as net income (loss) plus interest expense, depletion, depreciation and amortization expenses, deferred income taxes and other non-cash items. The following table provides a reconciliation of EBITDA to operating income (loss) for the periods presented.

	1997	1998	1999	2000	2001	2002
Operating income (loss)	$1,114	$(28,699)	$251	$3,647	$10,025	$9,435
Depletion, depreciation and amortization	3,437	9,268	9,077	8,820	13,888	15,034
Interest income	145	136	176	108	264	119
Other non-cash expenses	0	25,926	0	0	0	596
Cash gain (loss) on settlements of non-hedge derivitives	0	0	0	(620)	0	(14)
Cash portion of other income (expense)	0	0	(48)	0	(1,492)	(559)
EBITDA	$4,696	$6,631	$9,456	$11,955	$22,685	$24,611

Both the unlevered program rate of return and drilling capital rate of return are estimates of the return Brigham will earn on the capital it invested in its drilling programs for 2000, 2001 and 2002 assuming these programs perform in accordance with Brigham's third party reserve report.

Brigham's investment used to calculate the unlevered program rate of return includes actual capital expenditures for drilling associated with each program over the last three years and Brigham's total net capital expenditures for land and seismic and total general and administrative cost, both capitalized and expensed, incurred during each program year. Brigham's investment used to calculate the drilling capital rate of return includes actual capital expenditures for drilling associated with each program over the last three years. Any estimates of future capital expenditures for these three programs from Brigham's third party reserve report were also included as investments in the calculation of both the unlevered program rate of return and the drilling capital rate of return.

To calculate both the unlevered program rate of return and the drilling capital rate of return, actual profit (revenue less expenses) generated by each program over the last three years was calculated using the actual production volumes, actual prices (excluding the effects of hedging), actual lease operating expenses (including ad valorem taxes) and actual production taxes related to each program. To calculate future profits, estimates for production volumes, lease operating expenses (including ad valorem taxes) and production taxes from our third party reserve report were used for each program. Future estimated revenue was calculated using a flat price of $4.00 per Mcf for gas and $25.00 per barrel for oil.

Management believes that operating income (loss) for these three programs, calculated in accordance with GAAP, is the most directly comparable GAAP measure to the profit generated by our 2000, 2001 and 2002 drilling programs over the last three years. The following table provides a reconciliation of the profit for each of our drilling programs over the past three years to operating income (loss) for the periods presented. Profit used to calculate both the unlevered program rate of return and drilling capital rate of return for each of Brigham's drilling programs excludes depletion, depreciation and amortization expense, general and administrative expense (treated as an investment for each program) and gain (losses) associated with hedging. In the reconciliation below, these amounts were allocated to each program based on the actual production volumes associated with each program multiplied by the average per unit cost for Brigham in each given year.

	2000	2001	2002
Operating income (loss)	$3,689	$8,756	$11,263
Depletion, depreciation and amortization	1,933	9,230	11,559
General and administrative expense	757	2,542	3,937
(Gain) loss on hedging	2,320	5,697	1,463
Drilling program profit	$8,699	$26,225	$28,222

($000, except per share and per Mcfe data)	Year Ended December 31, 1997	1998	1999	2000	2001	2002
Operating Data:						
Revenue from the sale oil and natural gas	$9,184	$13,799	$13,799	$19,143	$32,293	$35,100
Total revenue	9,821	14,189	14,189	19,212	32,548	35,176
EBITDA *(see reconciliation on page 11)*	4,696	6,631	9,456	11,955	22,685	24,611
Discretionary cash flow *(see reconciliation on page 11)*	365	(3,226)	1,044	1,853	12,467	15,588
Net income (loss) to common stockholders	(1,117)[a]	(33,345)[b]	(21,628)[c]	16,337[d]	9,238	(576)
Per Diluted Share Data:						
Weighted average shares outstanding *(000)*	11,081	12,626	14,152	16,241	28,205[e]	16,138
Net income *(loss)* per share	($0.10)[a]	($2.64)[b]	($1.53)[c]	$1.01[d]	$0.44[e]	($0.04)
Capital Expenditure Data:						
Net land and G&G	$22,881	$40,784	($2,430)	$583	$2,560	$2,831
Net drilling	19,191	36,857	10,750	18,461	27,209	19,800
Property acquisitions *(sales)*	13,500	1,020	(17,143)	0	(207)	(604)
Capitalized G&A and interest	3,460	5,770	6,559	6,300	6,050	5,657
Total capital expenditures	$59,032	$84,431	($2,264)	$25,344	$35,612	$27,684
Balance Sheet Data:						
Cash and cash equivalents	$1,701	$2,569	$2,742	$837	$5,112	$15,318
Net oil and gas properties	84,294	134,317	112,066	129,490	151,891	164,980
Total assets	92,519	150,516	125,683	146,911	173,075	202,059
Total debt	32,000	94,786	97,341	82,000	91,721	81,797
Series A preferred stock	0	0	0	8,558	16,614	19,540
Series B preferred stock	0	0	0	0	0	4,777
Stockholders' equity	43,313	24,681	8,998	34,757	49,601	61,749
Per Mcfe Data:						
Revenue from the sale of oil and natural gas	$2.94	$2.08	$2.39	$2.90	$3.37	$3.51
Other revenue	0.20	0.06	0.05	0.01	0.03	0.01
Total revenue	$3.14	$2.14	$2.44	$2.91	$3.40	$3.52
Lease operating expenses	0.37	0.33	0.36	0.32	0.36	0.38
Production taxes	0.18	0.13	0.15	0.27	0.16	0.20
G&A expenses	1.14	0.70	0.56	0.47	0.38	0.44[f]
Gross profit per Mcfe	$1.45	$0.98	$1.37	$1.85	$2.50	$2.50

(a) Includes a net $1.2 million ($0.10 per share) non-cash deferred income tax charge related to Brigham's conversion from a partnership to a corporation in 1997.

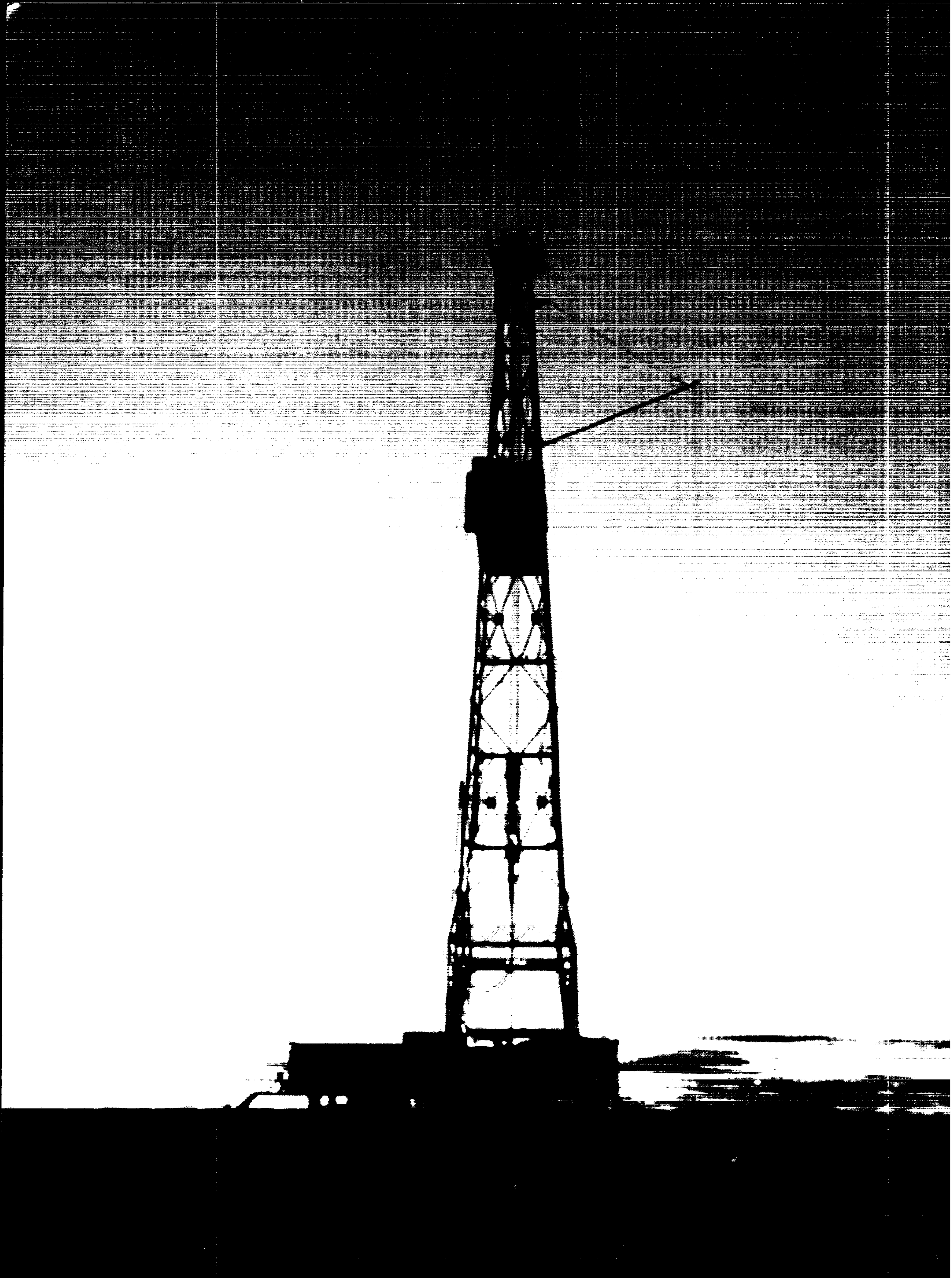
(b) Includes a $25.9 million ($2.05 per diluted share) capitalized ceiling impairment in 1998.

(c) Includes a $12.2 million ($0.86 per diluted share) loss on sale of natural gas and oil properties in 1999.

(d) Includes a $32.3 million ($1.99 per diluted share) extraordinary gain on refinancing of debt in 2000.

(e) Weighted average shares outstanding includes 11.0 million shares related to convertible debt and warrants issued with our Series A preferred stock that are deemed common stock equivalents under the "If-Converted" method. Interest expense of $826,000 related to the convertible debt and dividends and accretion of $2.4 million related to Series A preferred stock were added back to net income to calculate diluted per share amounts. Weighted average shares oustanding includes 1.2 million shares related to warrants and options that are deemed common stock equivalents under the "Treasury" method.

(f) Excludes non-recurring charge for non-cash compensation expense of $596,000 ($0.06 per Mcfe) related to vesting of options by an officer who left Brigham in 2002.



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

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2002

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number: 000-22433

Brigham Exploration Company
(Exact name of Registrant as Specified in its Charter)

Delaware	75-2692967
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

6300 Bridge Point Parkway, Building 2, Suite 500, Austin, Texas 78730
(Address of principal executive offices) (Zip Code)

(512) 427-3300
(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
None	None

Securities registered pursuant to Section 12(g) of the Act:
Common Stock, $.01 par value
(Title of Class)

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

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12 b-2 of the Act). Yes ☐ No ☒

As of June 28, 2002, the registrant had 16,061,042 shares of voting common outstanding. The aggregate market value of the registrants outstanding shares of voting common stock held by non-affiliates, based on the closing price of these shares on June 28, 2002 of $4.25 per share as reported on The Nasdaq Stock Market℠, was $34.2 million. Shares held by each executive officer and director and by each person who owns 10% or more of the outstanding common stock are considered affiliates. The determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of March 21, 2003, the registrant had 19,899,807 shares of voting common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the Registrant's 2003 Annual Meeting of Stockholders to be held on May 28, 2003, are incorporated by reference in Part III of this Form 10-K. Such definitive proxy statement will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2002.

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BRIGHAM EXPLORATION COMPANY

2002 ANNUAL REPORT ON FORM 10-K

PART I

ITEM 1. BUSINESS

Overview

We are an independent exploration, development and production company that utilizes 3-D seismic imaging and other advanced technologies to systematically explore for and develop domestic onshore oil and natural gas reserves. We focus our activity in provinces where we believe 3-D seismic technology can be used effectively to maximize our return on capital invested by reducing drilling risk and enhancing our ability to cost effectively grow reserves and production volumes. Our exploration and development activities are concentrated in the onshore Texas Gulf Coast, the Anadarko Basin of western Oklahoma and the Texas Panhandle, and West Texas. We believe that our focused approach of utilizing large scale 3-D seismic surveys and related technology in our core areas allows us to create and maintain a large inventory of high quality exploration and development prospects and provides us with the opportunity to enhance our exploration success and efficiently deploy our capital. The following is a brief summary of our assets at year-end 2002:

	For the Year Ended December 31, 2002		At December 31, 2002					
Province	Drilling CAPEX (Millions)	Production (MMcfe/d)	Proved Reserves (Bcfe)	SEC PV-10% (Millions)	% Gas	Net Wells	Net Acreage	3D Seismic Data (Sq. Miles)
Texas Gulf Coast	$13.3	14.7	65.3	$181.3	84%	14.7	8,242	2,686
Anadarko Basin	5.5	7.1	46.0	102.0	94%	27.2	32,713	2,197
West Texas / Other	1.0	6.0	9.7	24.1	17%	26.6	9,608	3,971
Total	$19.8	27.8	121.0	$307.4		68.5	50,563	8,854

Business Strategy

Our business strategy is designed to create stockholder value by generating superior growth in reserves, production volumes and cash flow through the successful execution of high rate of return exploration and development drilling. Key elements of our business strategy include:

Focus on Core Areas. We have accumulated an extensive inventory of 3-D seismic and geologic data and have developed a strong technical knowledge base in each of our core areas: the Vicksburg and Frio trends in the onshore Texas Gulf Coast, the Springer and Hunton trends in the Anadarko Basin, and the Horseshoe Atoll trend of West Texas. Since 1999, our drilling success in these core areas has resulted in five significant field discoveries and a resulting multi-year inventory of developmental drilling locations. We plan to focus a majority of our future capital expenditures in these core areas where we believe our accumulated data and knowledge base provide a substantial competitive advantage.

Internally Generate Inventory of High Quality Exploratory Prospects. We utilize 3-D seismic and other advanced technologies, including computer-aided exploration ("CAEX"), to generate and maintain a large inventory of high quality exploratory prospects. Virtually all of these prospects are internally-generated by our highly-skilled staff of ten geophysicists and geologists. We believe that our five recent field discoveries and our ability to constantly achieve low all sources finding costs, which over the last three, five and seven years have averaged $1.31, $1.46 and $1.35 per Mcfe, respectively, reflect the quality and depth of our 3-D delineated prospect inventory, as well as the strength of our exploration staff to continue to generate such opportunities.

Enhance Returns through Operational Control. Given that we originate the vast majority of our projects, we are generally able to retain operational control over all phases of our exploration and development activities. As of December 31, 2002, we operated approximately 61% of the PV-10% value of our proved developed producing reserves. Further, in 2002 we operated 75% of the wells we drilled, and expect to operate the majority of the wells planned for 2003. By operating, we can retain more control of the timing and selection of drilling projects, which enhances our ability to optimize our finding and development costs and maximizes our return on invested capital.

Capitalize on Exploration Successes Through Development of Recent Field Discoveries. From 1990 to 1999, we grew our reserves and production volumes primarily through successful 3-D delineated exploration drilling. Due to our recent exploratory drilling success, and the resulting growth in our inventory of developmental drilling locations, over 60% of our drilling capital expenditures in 2002 were developmental. For 2003, we intend to allocate approximately 60% of our drilling expenditures to the development of our recent new field discoveries. Furthermore, we anticipate that these fields will continue to provide us with an ongoing, multi-year program of developmental drilling.

Accelerate Development of Prospect Inventory Through Increased Drilling Expenditures. In order to capitalize on our deep inventory of exploration and developmental locations, we have a goal to increase our drilling expenditures in future periods. Consistent with this goal, in 2003 we have budgeted a 41% increase in drilling capital relative to drilling capital spent in 2002. We expect that the increased financial flexibility resulting from our recently completed private equity transaction, our recently completed new senior credit facility and our projected strong 2003 cash flow will enable us to significantly increase our developmental expenditures, while maintaining the pace of our exploration program.

Enhance Returns by Growing Production and Driving Down Unit Costs. Over the last three years, we have grown our annual production volumes by a compound annual growth rate of 23%. Such growth has enabled us to reduce our discretionary cash costs from $2.63 per Mcfe to $1.96 in 2002. Combined with our improved realizations, our discretionary cash margins expanded over the same three-year period from 10% to 44% in 2002, providing our company with substantially enhanced return on capital. Given current and anticipated commodity prices, combined with our continued success in cost effectively growing reserves and production volumes, we believe we can further enhance our return on capital in 2003.

Core Exploration and Development Properties

From our inception in 1990 through 1999, the vast majority of our drilling expenditures were allocated to exploration-oriented projects. Given our recent exploratory successes, we are benefiting from the allocation of a larger portion of our drilling expenditures toward the development of our recent discoveries.

For the three-year period ended December 31, 2002, we completed 73 gross wells (26.4 net) in 84 attempts for a completion rate of 87% at an average drilling finding cost of $0.96 per Mcfe. In 2002, we completed 22 gross wells (7.1 net) in 24 attempts for a completion rate of 92%, adding approximately 20.6 Bcfe of proved reserves at an average drilling finding cost of $0.96 per Mcfe. Set forth below is a summary of our recent activity and expected future activity in our core areas.

Texas Gulf Coast

The onshore Texas Gulf Coast province is a high-potential, multi-pay region that is extremely well suited for 3-D seismic exploration due to its substantial structural and stratigraphic complexity. We believe our exploration approach and our staff's extensive experience in this area provides us with significant competitive advantages. At December 31, 2002, our proved reserves in our Texas Gulf Coast province were approximately 65.3 Bcfe, representing 54% of our total proved reserves. We had also accumulated approximately 2,686 square miles (1.7 million acres) of 3-D seismic data and approximately 20,339 gross leasehold acres in our Texas Gulf Coast province. Over the past three years we have completed 36 gross wells (11.8 net) in 40 attempts for a completion rate of 90% and have added an estimated 43.1 Bcfe in estimated proved reserves at an average drilling finding cost of $0.98 per Mcfe.

During 2002, we completed 10 gross wells (2.9 net) in 10 attempts for a completion rate of 100%. We operated six of the 10 wells that we drilled in the onshore Gulf Coast in 2002. Four of the wells we drilled were exploratory and six were developmental. Our development drilling was focused on the Home Run and Providence Fields. In addition, we made a new field discovery adjacent to our Home Run and Triple Crown Fields with the successful completion of our Floyd Fault Block discovery well.

For 2003, we intend to focus our drilling activity in this province on the development of our Home Run, Triple Crown and Floyd Fault Block field discoveries in the Vicksburg, the testing of high reserve potential fault blocks adjacent to these fields, the development of our Providence Field in the Frio and the continued drilling of our 3-D delineated exploration inventory in the Frio trend. We expect to spend approximately $17.7 million to drill 17 wells in the onshore Gulf Coast. Approximately 53% percent of these capital expenditures are budgeted for development drilling, with the remainder allocated towards exploration drilling.

Anadarko Basin

The Anadarko Basin is a prolific natural gas province that we believe offers a combination of lower risk exploration and development opportunities in shallower horizons, as well as higher potential opportunities in the deeper section. At December 31, 2002, our proved reserves in the Anadarko Basin were 46.0 Bcfe, representing 38% of our total proved reserves. We had also accumulated approximately 2,197 square miles (1.4 million acres) of 3-D seismic data and approximately 70,130 gross leasehold acres in the Anadarko Basin. Over the past three years we have completed 26 gross wells (8.8 net) in 31 attempts for a completion rate of 84% and have added an estimated 19.2 Bcfe in proved reserves at an average drilling finding cost of $0.96 per Mcfe.

During 2002, we completed five gross wells (1.8 net) in seven attempts for a completion rate of 71%. We operated six of the seven wells that we drilled in the Anadarko Basin in 2002. Two of the wells we drilled were exploratory and five were developmental.

For 2003, we intend to continue to focus our drilling activity in this province on our 3-D delineated exploration and development inventory in the Springer and Hunton trends. We expect to spend approximately $7.6 million to drill 17 wells. Approximately 76% percent of these capital expenditures are budgeted for development drilling, with the remainder allocated towards exploration drilling.

West Texas

In West Texas, we have explored various carbonate reservoirs, including the Canyon Reef and Fusselman formations of the Horseshoe Atoll trend, the Canyon Reef of the Eastern Shelf, and the Mississippian Reef of the Hardeman Basin. At December 31, 2002, our proved reserves in this area were 9.7 Bcfe, representing approximately 8% of our total proved reserves. We had also accumulated approximately 3,695 square miles (2.4 million acres) of 3-D seismic data and approximately 16,820 gross leasehold acres in our West Texas core province. Over the past three years we have completed 11 gross wells (5.8 net) in 13 attempts for a completion rate of 85% and have added an estimated 6.1 Bcfe in proved reserves at an average drilling finding cost of $0.78 per Mcfe.

During 2002 we completed seven gross wells (2.4 net) in seven attempts for a completion rate of 100%. We operated six of the seven wells that we drilled in West Texas in 2002. Six of the wells we drilled were exploratory and one was developmental.

For 2003, we intend to continue to focus our drilling activities on our 3-D delineated exploration inventory in the Canyon Reef and Fusselman formations of the Horseshoe Atoll trend. We expect to spend approximately $2.6 million to drill seven wells. Approximately 48% of these capital expenditures are budgeted for development drilling, with the remainder allocated towards exploration drilling.

3-D Seismic Exploration

We have accumulated 3-D seismic data covering approximately 8,854 square miles (5.7 million acres) in over 28 geologic plays in seven basins and seven states. We typically acquire 3-D seismic data in and around existing producing fields where we can benefit from the imaging of producing analog wells. These 3-D defined analogs, combined with our experience in drilling over 550 wells in our 3-D project areas, provide us with a knowledge base to evaluate other potential geologic trends, 3-D seismic projects within these trends and prospective 3-D delineated drilling locations. Through our experience in the early and mid 1990's, we developed an expertise in the selection of geologic trends that are best suited for 3-D seismic exploration. As a result, in 1997 and 1998 we invested approximately $64 million in 3-D seismic and land in plays that we believed were providing optimal 3-D delineated drilling economics. We have used the experience that we have gained within our core trends to enhance the quality of subsequent projects in the same trend and other analogous trends, to lower finding and development costs, to compress project cycle times and to enhance our return on capital.

Over the last twelve years we have accumulated substantial experience exploring with 3-D seismic in a wide range of reservoir types and geologic trapping mechanisms. In addition, we typically acquire digital data bases for integration on our CAEX workstations, including digital land grids, well information, log curves, production information, geologic studies, geologic top data bases and existing 2-D seismic data. We use our knowledge base, local geological expertise and digital data bases integrated with 3-D seismic data to create maps of producing and potentially productive reservoirs. As such, we believe our 3-D generated maps are more accurate than previous reservoir maps (which generally are based on subsurface geological information and 2-D seismic surveys), enabling us to more precisely evaluate recoverable reserves and the economic feasibility of projects and drilling locations.

We have acquired most of our raw 3-D seismic data using seismic acquisition vendors on either a proprietary basis or through alliances affording the alliance members the exclusive right to interpret and use data for extended periods of time. In addition, we have participated in non-proprietary group shoots of 3-D seismic data (commonly referred to as "spec data") when we believe the expected full cycle project economics are justified, and we have exchanged certain interests in some of our non-core proprietary seismic data to gain access to additional 3-D seismic data. In most of our proprietary 3-D data acquisitions and alliances, we have selected the sites of projects, primarily guided by our knowledge and experience in the core provinces we explore; established and monitored the seismic parameters of each project for which data was shot; and typically selected the equipment that was used.

Combining our geologic and geophysical expertise with a sophisticated land effort, we manage the majority of our projects from conception through 3-D acquisition, processing and interpretation and leasing. In addition, we manage the negotiation and drafting of most of our geophysical exploration agreements, resulting in reduced contract risk and more consistent deal terms. Because we generate most of our projects, we can often control the size of the working interest that we retain as well as the selection of the operator and the non-operating participants. Consistent with our business strategy, we have increased the working interest we retain in our projects, based upon capital availability and perceived risk. Our average working interest in our 3-D seismic projects acquired during 1996, 1997 and 1998 was 37%, 67% and 80%, respectively. The 3-D seismic we acquired during 1999, 2000, 2001 and 2002 was primarily through the exchange of certain rights in some of our non-core 3-D seismic projects. Most of these exchanges did not include an industry participant, therefore we retained potentially all interest in any prospects generated from the newly acquired 3-D seismic data. In early 2003, we acquired approximately 84 square miles of new proprietary 3-D seismic data in our General Patton Project located in the Frio Trend of the Upper Texas Gulf Coast. We sold a working interest in this project to an industry participant on a promoted basis and thus retained a 50% working interest in the project.

Exploration and Development Staff

Our experienced exploration staff includes five geophysicists, five geologists, two computer applications specialists and two geophysical/geological/engineering technicians. Our geophysicists have different but complementary backgrounds, and their diversity of experience in varied geological and geophysical settings, combined with various technical specializations (from hardware and systems to software and seismic data processing), provides us with valuable technical intellectual resources. Our exploration staff of ten geophysicists and geologists has an average of more than 20 years of experience per person, most of which was acquired at both our company and various major and large independent oil companies. Our team was assembled according to the expertise that these individuals have within producing basins where we focus our exploration and development activities. By integrating both geologic and geophysical expertise within our project teams, we believe we possess a competitive advantage in our exploration approach. Occasionally, we will complement and leverage our exploration staff by seeking out alliances or retainer relationships with geologists and other technical professionals who have extensive experience in a particular area of interest.

Our land department staff includes four landmen and three lease and division order analysts.

Operations and Operations Staff

In an effort to retain better control of our project timing, drilling and operational costs and production volumes, we have significantly increased the percentage of the wells that we operate in the past several years. We operated 75% of the wells that we drilled during 2002, as compared with 10% of the wells we drilled during 1996. As a result of our increased operational control in recent years, wells operated by us constituted 61% of the PV-10% value of our proved developed producing reserves at year-end 2002, as compared to only 8% at year-end 1996.

Our operations staff includes five engineers that have drilling, reservoir, environmental and operations engineering experience primarily within our three core provinces. These engineers work closely with our explorationists and are integrally involved in all phases of the exploration and development process, including preparation of pre- and post-drill reserve estimates, well design, production management and analysis of full cycle risked drilling economics. We conduct field operations for our operated oil and natural gas properties through our field production superintendent and third party contract personnel.

Oil and Natural Gas Marketing and Major Customers

Most of our oil and natural gas production is sold under price sensitive or spot market contracts. The revenues generated by our operations are highly dependent upon the prices of and demand for oil and natural gas. The price we receive for our oil and natural gas production depends upon numerous factors beyond our control, including seasonality, weather, competition, the condition of the United

States economy, foreign imports, political conditions in other oil-producing and natural gas-producing countries, the actions of the Organization of Petroleum Exporting Countries, and domestic government regulation, legislation and policies. Decreases in the prices of oil and natural gas could have an adverse effect on the carrying value of our proved reserves and our revenues, profitability and cash flow. Although we are not currently experiencing any significant involuntary curtailment of our oil or natural gas production, market, economic and regulatory factors may in the future materially affect our ability to sell our oil or natural gas production. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors—Volatility Of Oil And Gas Markets Affect Us; Oil And Natural Gas Prices Are Volatile" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors—The Marketability Of Our Production Is Dependent On Facilities The Typically Do Not Own". For the year ended December 31, 2001, sales to Highland Energy Company and Lantern Petroleum Corporation represented approximately 60% of our oil revenue and 58% of our natural gas revenue. In 2002, in an effort to achieve better price realizations from the sale of our oil and natural gas, we decided to bring our commodities marketing activities in-house, enabling us to market and sell our oil and natural gas to a broader universe of potential purchasers. As a consequence, on March 1, 2002, we ended our oil purchase agreement with Lantern Petroleum and on July 1, 2002, we ended a similar gas sales and purchase arrangement with Highland Energy Company. Due to the availability of other markets and pipeline connections, we do not believe that the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations.

Competition

The oil and gas industry is highly competitive in all of its phases. We encounter competition from other oil and gas companies in all areas of our operations, including the acquisition of seismic and leasing options and oil and natural gas leases on properties to exploration and development of those properties. Our competitors include major integrated oil and natural gas companies and numerous independent oil and natural gas companies, individuals and drilling and income programs. Many of our competitors are large, well established companies with substantially larger operating staffs and greater capital resources than us. Such companies may be able to pay more for seismic and lease options on oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" "Risk Factors—We Face Significant Competition" and "Risk Factors—We Have Substantial Capital Requirements".

Operating Hazards and Uninsured Risks

Drilling activities are subject to many risks, including the risk that no commercially productive reservoirs will be encountered. There can be no assurance that new wells we drill will be productive or that we will recover all or any portion of our investment. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. The cost and timing of drilling, completing and operating wells is often uncertain. Our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, many of which are beyond our control, including title problems, weather conditions, delays by project participants, compliance with governmental requirements and shortages or delays in the delivery of equipment and services. Our future drilling activities may not be successful and, if unsuccessful, such failure may have a material adverse effect on our business, financial condition or results of operations. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors—Exploratory

Drilling Is A Speculative Activity Involving Numerous Risks And Uncertain Costs; We Are Dependent On Exploratory Drilling Activities". In addition, use of 3-D seismic technology requires greater pre-drilling expenditures than traditional drilling strategies. Although we believe that our use of 3-D seismic technology will increase the probability of drilling success, some unsuccessful wells are likely, and there can be no assurance that unsuccessful drilling efforts will not have a material adverse effect on our business, financial condition or results of operations.

Our operations are subject to hazards and risks inherent in drilling for and producing and transporting oil and natural gas, such as fires, natural disasters, explosions, encountering formations with abnormal pressures, blowouts, cratering, pipeline ruptures and spills, any of which can result in the loss of hydrocarbons, environmental pollution, personal injury claims and other damage to our properties and others. We maintain insurance against some but not all of the risks described above. In particular, the insurance we maintain does not cover claims relating to failure of title to oil and natural gas leases, trespass during 3-D survey acquisition or surface change attributable to seismic operations, business interruption or loss of revenues due to well failure. Furthermore, in certain circumstances in which insurance is available, we may not purchase it. The occurrence of an event that is not covered, or not fully covered, by insurance could have a material adverse effect on our business, financial condition and results of operations. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors—We Are Subject To Various Casualty Risks" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors—We May Not Have Enough Insurance To Cover Some Operating Risks".

Employees

On March 21, 2003, we had 52 full-time employees. None is represented by any labor union and we believe relations with our employees are good.

Facilities

Our principal executive offices are located in Austin, Texas, where we lease approximately 34,330 square feet of office space at 6300 Bridge Point Parkway, Building 2, Suite 500, Austin, Texas 78730.

Title to Properties

We believe we have satisfactory title, in all material respects, to substantially all of our producing properties in accordance with standards generally accepted in the oil and gas industry. Our properties are subject to royalty interests, standard liens incident to operating agreements, liens for current taxes and other inchoate burdens, which we believe, do not materially interfere with the use of or affect the value of such properties. Our senior credit facility and subordinated notes are secured by first and second liens, respectively, against substantially all of our oil and natural gas properties and other tangible assets. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Senior Credit Facility" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Senior Subordinated Notes".

Governmental Regulation

Our oil and natural gas exploration, production and marketing activities are subject to extensive laws, rules and regulations promulgated by federal and state legislatures and agencies. Failure to comply with such laws, rules and regulations can result in substantial penalties. The legislative and regulatory burden on the oil and gas industry increases our cost of doing business and affects our profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, we are unable to predict the future cost or impact of complying with such laws and regulations because they are frequently amended, interpreted and reinterpreted.

The State of Texas and many other states require permits for drilling operations, drilling bonds and reports concerning operations and impose other requirements relating to the exploration and production of oil and natural gas. These states also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from wells and the regulation of spacing, plugging and abandonment of such wells.

Environmental Matters

Our operations and properties are, like the oil and gas industry in general, subject to extensive and changing federal, state and local laws and regulations relating to environmental protection, including the generation, storage, handling, emission, transportation and discharge of materials into the environment, and relating to safety and health. The recent trend in environmental legislation and regulation generally is toward stricter standards, and this trend will likely continue. These laws and regulations may require the acquisition of a permit or other authorization before construction or drilling commences and for certain other activities; limit or prohibit seismic acquisition, construction, drilling and other activities on certain lands lying within wilderness and other protected areas; and impose substantial liabilities for pollution resulting from our operations. The permits required for many of our operations are subject to revocation, modification and renewal by issuing authorities. Governmental authorities have the power to enforce compliance with their regulations, and violations are subject to fines or injunction, or both. In the opinion of management, we are in substantial compliance with current applicable environmental laws and regulations, and we have no material commitments for capital expenditures to comply with existing environmental requirements. Nevertheless, changes in existing environmental laws and regulations or in interpretations thereof could have a significant impact on us, as well as the oil and gas industry in general. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") and comparable state statutes impose strict and arguably joint and several liability on owners and operators of certain sites and on persons who disposed of or arranged for the disposal of "hazardous substances" found at such sites. It is not uncommon for the neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes govern the disposal of "solid waste" and "hazardous waste" and authorize imposition of substantial fines and penalties for noncompliance. Although CERCLA currently excludes petroleum from its definition of "hazardous substance," state laws affecting our operations impose clean-up liability relating to petroleum and petroleum related products. In addition, although RCRA classifies certain oil field wastes as "non-hazardous," such exploration and production wastes could be reclassified as hazardous wastes thereby making such wastes subject to more stringent handling and disposal requirements.

Federal regulations require certain owners or operators of facilities that store or otherwise handle oil, such as us, to prepare and implement spill prevention, control countermeasure and response plans relating to the possible discharge of oil into surface waters. The Oil Pollution Act of 1990 ("OPA") contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States. For onshore and offshore facilities that may affect waters of the United States, the OPA requires an operator to demonstrate financial responsibility. Regulations are currently being developed under federal and state laws concerning oil pollution prevention and other matters that may impose additional regulatory burdens on us. In addition, the Clean Water Act and analogous state laws require permits to be obtained to authorize discharge into surface waters or to construct facilities in wetland areas. The Clean Air Act of 1970 and its subsequent amendments in 1990 and 1997 also impose permit requirements and necessitate certain restrictions on point source emissions of volatile organic carbons (nitrogen oxides "NOX" and sulfur dioxide "SO_2") and particulates with respect to certain of our operations, we are required to maintain such permits or meet general permit requirements. The Environmental Protection Agency ("EPA") and designated state agencies have in place regulations concerning discharges of storm water runoff and stationary sources of air emissions. These programs require covered facilities to obtain individual permits, participate in a group or seek coverage under an EPA general permit. Most agencies recognize the unique qualities of oil and gas exploration and production operations. Both the EPA and Texas Commission on Environmental Quality ("TCEQ") have adopted regulatory guidance in consideration of the operational limitations on these types of facilities and their potential to emit air pollutants. We believe that we will be able to obtain, or be included under, such permits, where necessary, and to make minor modifications to existing facilities and operations that would not have a material effect on us.

ITEM 2. PROPERTIES

Our exploration and development activities are focused primarily in the onshore Texas Gulf Coast, the Anadarko Basin of northwest Oklahoma and the Texas Panhandle and West Texas. We focus our activity in provinces where we believe 3-D seismic technology can be used effectively to maximize our return on capital invested by reducing drilling risk and enhancing our ability to cost effectively grow reserves and production volumes.

Texas Gulf Coast

The onshore Texas Gulf Coast region is a high potential, multi-pay province that lends itself to 3-D seismic exploration due to its substantial structural and stratigraphic complexity. We believe our established 3-D seismic exploration approach and our exploration staff's extensive experience in the Texas Gulf Coast provide us with significant competitive advantages. We have assembled a digital database including geographical, production, geophysical and geological information of the Texas Gulf Coast that our staff evaluates on CAEX workstations. The majority of our Texas Gulf Coast activity is currently concentrated in the Vicksburg and Frio trends, where we completed eight wells in eight attempts in 2002.

Vicksburg Trend

Our 3-D seismic inventory in the Vicksburg trend consists of approximately 179 square miles of 3-D seismic data (114,560 acres) located primarily in Brooks County in south Texas. The primary exploration targets within this area are structural features at depths ranging from 9,000 to 14,000 feet.

Since late 1999, we have completed 13 wells in 13 attempts in the Vicksburg play in South Texas at a proved developed drilling finding cost of $1.55 per Mcfe. However, early in our Vicksburg drilling program we experienced operational problems, primarily due to poor cement jobs. A few years ago we modified our drilling and completion techniques and have had excellent results ever since. Excluding three of the early wells with the poor cement jobs, our average drilling finding cost for proved developed reserves for the other ten wells we have drilled in this play has been approximately $1.34 Mcfe. For 2003, we have budgeted approximately $9.2 million to drill approximately four developmental wells and three exploratory wells in this area.

Since 1999, our exploration efforts in this trend have been focused in our Diablo Project. During 2002, we added to our exploration success in the Diablo project with our Floyd Fault Block discovery. Including this discovery, the Diablo project has provided three significant Vicksburg field discoveries. In 1999, we discovered the Home Run Field and in 2001 we discovered the Triple Crown Field. We own, along with a major integrated oil company participant, 10,000 gross and net acres of leasehold in the Diablo Project, and we acquired a 54 square mile proprietary 3-D program over the area in 1997 and

1998. We retain a 34% working interest in the project, but have increased our pre-payout working interest to 50% in select acreage that was subsequently drilled as our Triple Crown Field discovery.

Floyd Fault Block Vicksburg Discovery. We drilled our Floyd Fault Block discovery, the Sullivan #8, in December 2002. We retained a 34% working and 25% revenue interest in the Sullivan #8, which proves up reserves in one of several fault blocks adjacent to our Home Run and Triple Crown Fields. The Sullivan #8 encountered approximately 172 feet of apparent net pay in several Lower Vicksburg pay intervals at depths between 12,900 and 13,650 feet. The quantity of pay encountered is approximately triple that encountered in our typical Home Run Field Vicksburg wells.

The Sullivan #8, began producing to sales in March 2003 at a rate of approximately 9.2 MMcf of natural gas and 580 barrels of condensate per day (12.7 MMcfed), or approximately 3.2 MMcfed net to our 25% revenue interest, with a flowing tubing pressure of approximately 8,900 psi. This flowing tubing pressure is approximately 4,000 psi higher than our typical Home Run Field Vicksburg wells at comparable production rates, indicating the higher deliverability of the Floyd Fault Block reservoirs. The current production rate is limited by the production facilities, and we expect the operator of the well to expand the facilities in order to produce the well at higher rates. We estimate that the Floyd Fault Block will require up to nine additional wells for full development, four of which are proved undeveloped. We expect to spud our first development well in the second quarter of 2003 and could drill up to three additional wells in 2003.

Home Run Field & Triple Crown Vicksburg Field. We discovered the Home Run Field in late 1999 and the Triple Crown Field in 2001. To date, we have drilled and completed 12 consecutive wells in these fields. During 2002, we drilled and completed three wells in the Home Run Field. These wells include:

- The Palmer #5R, which began producing to sales in September 2002 at a rate of approximately 9.0 MMcf of natural gas and 520 barrels of condensate per day (12.1 MMcfed), or approximately 3.2 MMcfed net to Brigham's 26% revenue interest.
- The Palmer #3ST began producing to sales in October 2002, at a rate of 5.6 MMcf of natural gas and 240 barrels of condensate per day (7.0 MMcfed), or 2.0 MMcfed net to Brigham's 29% revenue interest.
- The Palmer State #6 began producing to sales in March 2003, at a rate of 12.2 MMcf of natural gas and 550 barrels of condensate per day (15.5 MMcfed), or 4.5 MMcfed net to Brigham's 29% revenue interest.

We believe the fields could require up to 35 additional wells for full development.

Adjacent Fault Blocks to Home Run and Triple Crown. We also anticipate testing at least one of the other adjacent fault blocks during 2003. One of these fault blocks is adjacent to our Floyd Fault Block discovery, and we believe that a portion of this fault block is juxtaposed to pay intervals found in the Sullivan #8. This fault block, and other adjacent fault blocks, provide up to 15 additional locations. We believe that all of the adjacent fault blocks are located structurally high to the adjacent Triple Crown Field, and structurally low to the adjacent Home Run Field, providing us with significant probable and possible reserve potential.

Frio Trend

In the Frio trend of the Upper Texas Gulf Coast, we have accumulated an inventory of over 1,172 square miles of predominantly non-proprietary 3-D seismic data (696,320 acres) located primarily in Matagorda and Brazoria Counties in south Texas. In early 2003, we added to our 3-D seismic inventory when we acquired 84 square miles of proprietary seismic data within our General Patton project in the Frio trend. We sold a 50% working interest in the General Patton project to a participant on a promoted basis while retaining operations, and as a result we paid 33.3% of the seismic and pre-seismic land costs for a 50% working interest in the project. We are targeting both the shallow non-pressured and the deeper pressured Frio sands, analogous to our recent high rate discoveries in the trend. Our completions in this play are typically providing quick payouts of drilling and completion costs, and attractive rates of return on our drilling capital investments.

Since late 2000, we have completed 10 Frio tests in 11 attempts, at an estimated average drilling finding cost for proved developed reserves of $0.89 per Mcfe. For 2003, we expect to spend approximately $6.3 million to drill approximately two developmental wells and five exploratory wells in this area.

Providence Frio Field. We discovered the Providence Field during the fourth quarter of 2001, when we drilled and completed the Staubach #1 well. Including the Staubach #1 discovery well in 2001, we have now successfully completed four wells in the Providence Field. These wells include:

- The Staubach #1 (41% initial working interest) began producing to sales in February 2002 at a rate of 2,000 barrels of oil per day and 5.0 MMcf of natural gas per day (17.0 MMcfed), or approximately 5.4 Mmcfed to our initial 32% net revenue interest. The Staubach #1 paid out its drilling and completion costs in approximately three months. Upon payout, our net revenue interest in the Staubach #1 reverted to 27%.
- The Burkhart #1R (41% initial working interest), the relief well for the Burkart #1, was completed in July 2002 and began producing to sales at a rate of 1,700 barrels of oil per day and 10.0 MMcf of natural gas per day (20.2 Mcfed), or 6.3 MMcfed net to our initial 31% revenue interest. The Burkhart #1R paid out its drilling and completion costs in approximately three months, at which time our net revenue interest reverted to 22%.
- The Huebner #1 (34% working interest) was completed in November 2002 and began producing to sales at a rate of 2,230 barrels of oil per day and 6.1 MMcf of natural gas per day (19.5 MMcfed), or 4.9 MMcfed net to our 25% revenue interest. The Huebner #1 paid out its drilling and completion costs in approximately three months. The Huebner #1 is not subject to any reversionary interests.
- The Matthes-Huebner #1 (initial 43% working interest) was completed in December 2002 and began producing to sales in January 2003 at a rate of 2,518 barrels of oil per day and 7.7 MMcf of natural gas per day (22.8 MMcfed), or 7.3 MMcfed net to our 32% revenue interest. The Matthes-Huebner #1 well found two prolific pay intervals unlike the one pay interval found in each of the three previously drilled wells, and its initial rate is the highest of the Providence Field wells completed to date. We estimate the well paid out its drilling and completion costs in less than two months, and upon payout our net revenue interest reverted to 28%.

We are currently drilling the Huebner #3, our fifth Providence Field well, with a 40% working interest. The Huebner #3 is not subject to any reversionary interests. This well, like the recently completed Matthes-Huebner #1, has two potential pay intervals and we expect results in the second quarter 2003.

Most of our production from the Providence Field in 2002 came from the first two wells drilled, the Staubach #1 and the Burkhart #1R. Gross production from the Providence Field averaged approximately 22 MMcfed during 2002. With the addition of the Huebner #1, average daily production from the Providence Field during the fourth quarter 2002 was approximately 38 MMcfed. In March 2003, we had four Providence Field wells on line producing approximately 50 MMcfed, or 13 MMcfed net to our revenue interest.

Other Frio. As part of our ongoing Frio exploration program, in October 2002 we completed the Carr #1, a Frio bright spot exploration discovery in Brazoria County. We operated and retained a 37%

working interest in the well, which began producing to sales in early December 2002 at an initial rate of approximately 1.8 MMcf of natural gas per day and 50 barrels of oil per day (2.1 MMcfed), or approximately 0.6 MMcfed net to our 29% revenue interest.

In addition to our ongoing drilling program in the Frio, we continue to generate additional drilling inventory from our data base of more than 1,170 square miles of 3-D seismic data in the trend. Of this data, we are currently processing the 84 square miles of new proprietary 3-D seismic data that is our General Patton project. We acquired this data along the same trend that has provided most of our recent Frio discoveries, including the prolific Providence Field. We operate and retain a 50% working interest in this new project and have a strong land position of over 14,000 acres. Our staff began interpreting the data and defining drilling prospects during the first quarter of 2003, and we hope to commence our drilling program here during the second half of 2003. The company is assembling additional 3-D projects targeting the highly prolific Frio objective.

Dinn Ranch Wilcox Field

The Dinn Ranch Field was reportedly producing over 100 MMcf of natural gas per day in early 2003. We have participated in two wells in the field thus far. The first well, the Lopez #1, has experienced operational difficulties and its completion has been delayed. The second well, the Lopez #3, was producing to sales in February 2003 at a rate of approximately 16.5 MMcf of natural gas per day. We retain an overriding royalty interest in the Lopez #1 and the Lopez #3 that converts into a 12.5% working interest at 100% payout of drilling and completion costs, and a 25% working interest after 200% payout. At current production rates and commodity prices, we could convert to a 12.5% and possibly a 25% working interest in the Lopez #3 by year-end 2003. We expect a third well to spud in 2003, in which we expect to retain a 25% ground floor working interest.

Anadarko Basin

The Anadarko Basin is located in northwest Oklahoma and the Texas Panhandle. We believe this prolific natural gas province offers a combination of lower risk exploration and development opportunities in shallower horizons and deeper higher potential objectives that have been relatively under explored. The stratigraphic and structural objectives in the Anadarko Basin can provide excellent targets for 3-D seismic imaging. In addition, drilling economics in the Anadarko Basin are enhanced by the multi-pay nature of many of these prospects, with secondary or tertiary targets serving as either incremental value or as alternatives in the event the primary target zone is not productive. Our activity is currently focused in the Springer Channel and Hunton trends, where we completed four wells in six attempts in 2002.

Springer Trend

Our 3-D inventory in the Springer trend consists of approximately 630 square miles (403,200 acres) of 3-D seismic data covering portions of Dewey, Blaine, Canadian and Caddo Counties, Oklahoma. Our activities in this area target buried sand channels at depths of 9,000 to 12,000 feet, as well as other secondary objectives. We began our operations in the Springer trend in 1991 and our interpretation and prospect generation efforts are still underway.

Since 2000, we have completed nine Springer wells in 13 attempts, at an estimated average drilling finding cost for proved developed reserves of $1.03 per Mcfe. Approximately 50% of these completions perform at a very high level, and as a result our overall program has provided extremely strong rates of return. Recently we entered into a joint venture that encompasses approximately 14,000 gross acres, greatly expanding our acreage position in this competitive trend. We have budgeted approximately $4.1 million to drill six developmental wells and six exploratory wells in this area in 2003.

Hunton Trend

Our 3-D seismic inventory in the Hunton trend consists of approximately 763 square miles (488,320 acres) of 3-D seismic data covering portions of Wheeler, Hemphill and Roberts Counties, Texas and Beckham County, Oklahoma. The primary exploration targets within this area are high potential, structural features at depths ranging from 7,500 to 25,000 feet. The trend has historically provided longer life reserves relative to our typical Texas Gulf Coast wells, but with the same type of prolific recoveries.

Since late 2000, we have completed two wells in the Hunton trend in two attempts. In late 2000, we drilled the discovery well for our Mills Ranch Field, the Mills Ranch #1, and in 2002 the first development well, the Mills Ranch #2, at an average estimated proved developed drilling finding cost of $0.58 per Mcfe. We have budgeted approximately $2.8 million to drill four developmental wells during 2003.

Mills Ranch Field. In July 2000, we spud the Mills Ranch #1, which was drilled directionally to a total depth of over 25,000 feet. We operated and retained a 64% working interest in the well, which encountered approximately 1,200 feet of gross pay and 340 feet of measured depth net pay (240 feet of calculated true vertical net pay) in three Hunton intervals. The Mills Ranch #1 began producing from one of the Hunton pay intervals in January 2001 at approximately 9.5 MMcf of natural gas and 90 barrels of condensate per day. The discovery well paid out its drilling and completion costs during its first year of production, and at year-end 2002 had produced 3.2 Bcfe and was producing approximately 3.2 MMcfed.

In the third quarter 2002, we began drilling the first offset to this discovery, the Mills Ranch #2. We retained a 64% working interest in the Mills Ranch #2, which encountered the basal Hunton porosity zone approximately 400 feet high to the comparable zone in the discovery well. After running production casing to a depth of approximately 23,900 feet, we perforated and stimulated the lower Hunton intervals. The well began producing at an initial rate of approximately 6.7 MMcf of natural gas per day with associated condensate. The upper intervals were then stimulated and commingled into the producing stream. The recent production rate was approximately 1.8 MMcfed, or approximately 0.9 MMcfed net to our 50% revenue interest. Given what we have learned about the remaining reserve potential of the field, we plan to drill at least one additional development well in the Mills Ranch Field in 2003. We expect to operate and retain a 64% working interest in this well.

West Texas

Our drilling activity in our West Texas province has been focused primarily in various carbonate and predominantly oil reservoirs, including the Canyon Reef and Fusselman formation of the Horseshoe Atoll trend, the Canyon Reef of the Eastern Shelf, and the Mississippian Reef of the Hardeman Basin, at depths ranging from 7,000 to 13,000 feet. We are currently focused on the Canyon Reef and Fusselman formations in the Horseshoe Atoll trend, where we completed seven wells in seven attempts in 2002.

Horseshoe Atoll Trend

We have an inventory of approximately 778 square miles (497,920 acres) of 3-D seismic data primarily covering portions of Scurry, Howard, Dawson and Borden Counties in the Horseshoe Atoll trend, where we have accumulated substantial experience exploring with 3-D seismic over the last twelve years. In 2002, and in prior years, we frequently sold working interests in our West Texas drilling prospects to industry participants on a promoted basis, which has reduced our drilling risk while also contributing to lower finding costs and higher rates of return.

Since 2000, we have completed eight wells in eight attempts in the trend at an estimated average drilling finding cost for proved developed reserves of $0.52 per Mcfe. For 2003, we have budgeted approximately $2.6 million to drill two developmental wells and five exploratory wells.

Our most significant completions in West Texas during 2002 were in the Fusselman formation in the Horseshoe Atoll trend. In May 2002 we completed the Casa Grande 2 #1 as the discovery well for the Conner Shea Fusselman Field in West Texas. We operated the Casa Grande 2 #1 with a 50% working interest, which began producing approximately 230 barrels of oil per day, or approximately 0.6 MMcfed net to our 43% revenue interest. In February 2003, we completed another well in the Conner Shea Fusselman Field, the Brigham operated Casa Grande 12 #1. The Casa Grande 12 #1 began producing at approximately 100 barrels of oil per day, or approximately 0.2 MMcfed net to our 41% revenue interest.

Oil and Natural Gas Reserves

Our estimated total net proved reserves of oil and natural gas as of December 31, 2002, 2001 and 2000 and the present values attributable to these reserves as of those dates were as follows:

	As of December 31,		
	2002	2001	2000
Estimated net proved reserves:			
Natural gas (MMcf)	99,428	88,594	78,167
Oil (MBbls)	3,607	3,748	2,870
Natural gas equivalent (MMcfe)	121,070	111,081	95,388
Proved developed reserves as a percentage of proved reserves	46%	49%	52%
Present value of future net revenues (in thousands)	$307,374	$146,807	$497,666
Standardized measure (in thousands)	$239,698	$120,924	$359,228
Base price used to calculate reserves (1):			
Natural gas ($ per Mcf)	$ 4.74	$ 2.57	$ 10.42
Oil ($ per Bbl)	$ 31.25	$ 19.84	$ 26.83

(1) These base prices were adjusted to reflect applicable transportation and quality differentials on a well-by-well basis to arrive at realized sales prices used to estimate our reserves at these dates.

The reserve estimates reflected above were prepared by Cawley, Gillespie & Associates, Inc., our independent petroleum consultants, and are part of reports on our oil and natural gas properties prepared by Cawley Gillespie.

In accordance with applicable requirements of the SEC, estimates of our net proved reserves and future net revenues are made using sales prices estimated to be in effect as of the date of such reserve estimates and are held constant throughout the life of the properties (except to the extent a contract specifically provides for escalation). Estimated quantities of net proved reserves and future net revenues therefrom are affected by oil and natural gas prices, which have fluctuated widely in recent years. There are numerous uncertainties inherent in estimating oil and natural gas reserves and their estimated values, including many factors beyond our control. The reserve data set forth in this Form 10-K represent only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geologic interpretation and judgment. As a result, estimates of different engineers, including those used by us, may vary. In addition, estimates of reserves are subject to revision based upon actual production, results of future development and exploration activities, prevailing oil and natural gas prices, operating costs and other factors. The revisions may be material. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered and are highly dependent upon the accuracy of the assumptions upon which they are based. Our estimated net proved reserves have not been filed with or included in reports to any federal agency. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors—We Are Subject To Uncertainties In Reserve Estimates And Future Net Cash Flows".

Estimates with respect to net proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations in the estimated reserves that may be substantial.

Drilling Activities

We drilled, or participated in the drilling of, the following number of wells during the periods indicated:

	Year Ended December 31,					
	2002		2001(1)		2000(2)	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells(3):						
Natural gas	3	0.8	5	1.6	6	1.9
Oil	8	2.7	5	3.7	3	0.9
Non-productive	1	0.7	4	1.1	2	1.0
Total	12	4.2	14	6.4	11	3.8
Development wells(4):						
Natural gas	8	2.4	15	4.6	15	5.8
Oil	2	0.9	1	0.1	1	0.7
Non-productive	2	0.6	2	0.2	1	0.8
Total	12	3.9	18	4.9	17	7.3

(1) Excludes one gross (0.3 net) development well that was temporarily abandoned during drilling due to operational difficulties encountered prior to reaching total depth. We re-entered and completed this temporarily abandoned well during 2002.

(2) Excludes one gross (1.0 net) exploratory well that was temporarily abandoned during drilling due to operational difficulties encountered prior to reaching total depth. We re-entered and completed this temporarily abandoned well during 2001.

(3) From January 1, 2003 through March 21, 2003, we drilled or participated in the drilling of one gross (0.3 net) exploratory well, which was non-productive.

(4) From January 1, 2003 through March 21, 2003, we drilled or participated in the drilling of three gross (0.8 net) development wells which were in the process of drilling at March 21, 2003.

We do not own drilling rigs and the majority of our drilling activities have been conducted by independent contractors or industry participant operators under standard drilling contracts. We operated 75% of the wells we participated in during 2002.

Productive Wells and Acreage

Productive Wells

The following table sets forth our ownership interest as of December 31, 2002 in productive oil and natural gas wells in the areas indicated.

	Natural Gas		Oil		Total	
Province:	Gross	Net	Gross	Net	Gross	Net
Texas Gulf Coast	34	10.2	19	4.5	53	14.7
Anadarko Basin	92	22.7	18	4.5	110	27.2
West Texas	13	1.9	81	24.7	94	26.6
Total	139	34.8	118	33.7	257	68.5

Productive wells consist of producing wells and wells capable of production, including wells waiting on pipeline connection. Wells that are completed in more than one producing horizon are counted as one well. Of the gross wells reported above, two had multiple completions.

Acreage

Undeveloped acreage includes leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether or not such acreage contains proved reserves. The following table sets forth the approximate developed and undeveloped acreage that we held a leasehold, mineral or other interest at December 31, 2002:

	Developed		Undeveloped		Total	
Province:	Gross	Net	Gross	Net	Gross	Net
Texas Gulf Coast	9,825	3,582	10,514	4,660	20,339	8,242
Anadarko Basin	32,896	12,604	37,234	20,109	70,130	32,713
West Texas	6,894	1,986	9,926	5,040	16,820	7,026
Other	535	160	5,597	2,422	6,132	2,582
Total	50,150	18,332	63,271	32,231	113,421	50,563

All the leases for the undeveloped acreage summarized in the preceding table will expire at the end of their respective primary terms unless the existing leases are renewed, production has been obtained from the acreage subject to the lease prior to that date, or some other "savings clause" is implicated. The following table sets forth the minimum remaining terms of leases for the gross and net undeveloped acreage:

	Acres Expiring	
Twelve Months Ending:	Gross	Net
December 31, 2003	9,014	6,324
December 31, 2004	27,449	16,001
December 31, 2005	5,366	5,333
Thereafter	—	—
Total	41,829	27,658

In addition, as of December 31, 2002 we had lease options to acquire an additional 18,316 gross and 12,656 net acres, all of which expire in 2003.

Volumes, Prices and Production Costs

The following table sets forth the production volumes, average prices received before hedging, average prices received after hedging and average production costs associated with our sale of oil and natural gas for the periods indicated.

	Year Ended December 31,		
	2002	2001	2000
Production:			
Natural gas (MMcf)	5,791	6,766	4,431
Oil (MBbls)	701	468	362
Natural gas equivalent (MMcfe)	9,996	9,573	6,600
Average sales price per unit:			
Natural gas revenues (per Mcf)	$ 3.33	$ 4.29	$ 4.06
Effects of hedging activities (per Mcf)	(0.12)	(1.18)	(2.12)
Average price (per Mcf)	$ 3.21	$ 3.11	$ 1.94
Oil revenues (per Bbl)	$25.17	$24.38	$29.47
Effects of hedging activities (per Bbl)	(1.62)	(0.33)	(0.30)
Average price (per Bbl)	$23.55	$24.05	$29.17
Total natural gas and oil revenues (per Mcfe)	$ 3.70	$ 4.22	$ 4.34
Effects of hedging activities (per Mcfe)	(0.19)	(0.85)	(1.44)
Average price (per Mcfe)	$ 3.51	$ 3.37	$ 2.90
Average production costs:			
Lease operating expenses (per Mcfe)	$ 0.38	$ 0.36	$ 0.32
Production taxes (per Mcfe)	$ 0.20	$ 0.16	$ 0.27

Costs Incurred

The costs incurred in oil and natural gas acquisition, exploration and development activities are as follows (in thousands):

	Year Ended December 31,		
	2002(1)	2001(2)	2000(3)
		(in thousands)	
Exploration	$12,693	$18,210	$14,238
Property acquisition	3,213	3,437	2,540
Development	13,301	14,353	12,555
Proceeds from participants	(703)	(135)	(40)
Costs incurred	$28,504	$35,865	$29,293

(1) Excludes $821,000 of proceeds from the sale of interests in properties, projects and prospects in 2002.

(2) Excludes $262,000 of proceeds from the sale of interests in properties, projects and prospects in 2001.

(3) Excludes $3.9 million of proceeds from the sale of interests in properties, projects and prospects in 2000.

Costs incurred represent amounts we incurred for exploration, property acquisition and development activities. Periodically, we receive reimbursement of certain costs from participants in our projects subsequent to project initiation in return for an interest in the project. These payments are described as "Proceeds from participants" in the table above.

ITEM 3. LEGAL PROCEEDINGS

We are, from time to time, party to certain lawsuits and claims arising in the ordinary course of business. While the outcome of lawsuits and claims cannot be predicted with certainty, we do not expect these matters to have a materially adverse effect on our financial condition, results of operations or cash flows.

On June 1, 2001, Leonel Garcia, a landowner in Brooks County, Texas, filed suit against us claiming that we transported natural gas under his property through an existing pipeline without his consent. Mr. Garcia claimed $1.2 million in actual damages and $3 million in exemplary damages. In May 2002, we settled the case through mediation for a cash payment of $125,000. We are now using an alternate pipeline.

On November 20, 2001, we filed a lawsuit in the District Court of Travis County, Texas against Steve Massey Company, Inc. for breach of contract. The Petition claims Massey furnished defective casing to us, which ultimately led to the casing failure of the Palmer "347" No. 5 well and the loss of the Palmer #5 as a producing well. We believe the amount of damages incurred due to the loss of the Palmer #5 may exceed $5 million. Massey joined as additional defendants to the lawsuit other parties that had responsibility for the manufacture, importation or fabrication of the casing for its use in the Palmer #5. The case is currently in discovery. A trial has been set for August 2003.

On February 20, 2002, Massey filed an Original Petition to Foreclose Lien in Brooks County, Texas. Massey's Petition claims we breached our contract for failure to pay for the casing Massey has furnished us for the Palmer #5 (and that our claim forming the basis of the lawsuit described in the paragraph above is defective). Massey's Petition claims we owe Massey a total of $445,819. Our Motion to Transfer Venue to Travis County, Texas, and our Motion to Consolidate Massey's claim with our suit against Massey pending in Travis County, were recently granted. If Massey is successful in its claim, Massey would have the right to foreclose its lien against the well, associated equipment and our leasehold interest related to the well. At this point in time, we cannot predict the outcome of either our claim or Massey's claim.

On July 11, 2002, an employee of a contractor on our Burkhart #1-R location, Matagorda County, Texas, was killed in an accident. The United States Department of Labor Occupational Safety & Health Administration investigated the accident, and issued three citations and imposed a total of $168,000 in fines. We are appealing the citations, but at this time, cannot predict the outcome of that appeal.

On October 8, 2002, relatives of the contractor's employee filed, in the district court for Matagorda County, Texas, a wrongful death action against us and three of our contractors in connection with his accidental death on July 11, 2002, on our Burkhart #1-R location. Plaintiffs are seeking unspecified actual and punitive damages. At this point in time, we cannot predict the outcome of this case, but believe we have sufficient insurance to cover the claim.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITYHOLDERS

No matter was submitted to a vote of our security holders during the fourth quarter of 2002.

EXECUTIVE OFFICERS OF THE REGISTRANT

Pursuant to Instruction 3 to Item 401(b) of the Regulation S-K and General Instruction G(3) to Form 10-K, the following information is included in Part I of this report.

The following table sets forth certain information concerning Brigham's executive officers as of March 21, 2003:

Name	Age	Position
Ben M. Brigham	43	Chief Executive Officer, President and Chairman
Eugene B. Shepherd, Jr.	44	Chief Financial Officer
David T. Brigham	42	Executive Vice President—Land and Administration
A. Lance Langford	40	Senior Vice President—Operations
Jeffery E. Larson	44	Senior Vice President—Exploration

Ben M. "Bud" Brigham has served as our Chief Executive Officer, President and Chairman of the Board since we were founded in 1990. From 1984 to 1990, Mr. Brigham served as an exploration geophysicist with Rosewood Resources, an independent oil and gas exploration and production company. Mr. Brigham began his career in Houston as a seismic data processing geophysicist for Western Geophysical, Inc. a provider of 3-D seismic services, after earning his B.S. in Geophysics from the University of Texas. Mr. Brigham is the husband of Anne L. Brigham, Director, and the brother of David T. Brigham, Executive Vice President—Land and Administration.

Eugene B. Shepherd, Jr., has served as Chief Financial Officer since June 2002. Mr. Shepherd has approximately 20 years of financial and operational experience in the energy industry. Prior to joining us, Mr. Shepherd served as Integrated Energy Managing Director at ABN AMRO Bank, a large European bank, where he executed merger and acquisition advisory, capital markets and syndicated loan transactions for energy companies. From 1998 to 2000, Mr. Shepherd was an investment banking Director for Prudential Securities Incorporated, where he executed a wide range of transactions for energy companies. Prior to joining Prudential Securities Incorporated, Mr. Shepherd served as an investment banker with Stephens Inc. for eight years and with Merrill Lynch Capital Markets for four years. Prior to joining Merrill Lynch Capital Markets, Mr. Shepherd worked for over four years as a petroleum engineer for both Amoco Production Company and the Railroad Commission of Texas. He has a B.S. in Petroleum Engineering and an MBA, both from the University of Texas at Austin.

David T. Brigham joined us in 1992 and has served as Executive Vice President—Land and Administration since June 2002 and Corporate Secretary from March 2001 to September 2002. Mr. Brigham served as Senior Vice President—Land and Administration from March 2001 to June 2002, Vice President—Land and Administration and Corporate Secretary from February 1998 to March 2001, and as Vice President—Land and Legal from 1994 until February 1998. From 1987 to 1992, Mr. Brigham was an oil and gas attorney with Worsham, Forsythe, Sampels & Wooldridge. Before attending law school, Mr. Brigham was a landman for Wagner & Brown Oil and Gas Producers, an independent oil and gas exploration and production company. Mr. Brigham holds a B.B.A. in Petroleum Land Management from the University of Texas and a J.D. from Texas Tech School of Law. Mr. Brigham is the brother of Ben M. Brigham, Chief Executive Officer, President and Chairman of the Board.

A. Lance Langford joined us in 1995 as Manager of Operations and served as Vice President—Operations from January 1997 to March 2001, and has served as Senior Vice President—Operations since March 2001. From 1987 to 1995, Mr. Langford served in various engineering capacities with Meridian Oil Inc., handling a variety of reservoir, production and drilling responsibilities. Mr. Langford holds a B.S. in Petroleum Engineering from Texas Tech University.

Jeffrey E. Larson joined us in 1997 and was Vice President—Exploration from August 1999 to March 2001, and has been Senior Vice President—Exploration since March 2001. Mr. Larson joined us in October 1997 as Gulf Coast Exploration Manager in our Houston office where he co-managed our expansion into the onshore Gulf Coast province through the initiation and assemblage of 3-D seismic projects and drilling opportunities. In November 1998, Mr. Larson relocated to our corporate office in Austin where he assumed an expanded role in directing our exploration activities in the Anadarko Basin, in addition to the further advancement of our Gulf Coast activities. Prior to joining us, Mr. Larson was an explorationist in the Offshore Department of Burlington Resources, a large independent exploration company, where he was responsible for generating exploration and development drilling opportunities. Mr. Larson worked at Burlington for seven years in various roles of increasing responsibility within its exploration department. Prior to Burlington, Mr. Larson spent five years at Exxon as a Production Geologist and Research Scientist. He has a B.S. in Earth Science from St. Cloud State University in Minnesota and a M.S. in Geology from the University of Montana.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Our common stock has been publicly traded on The NASDAQ Stock Market[sm] under the symbol "BEXP" since our initial public offering effective May 8, 1997. The following prices represent the range of high and low sales prices of our common stock on NASDAQ for the period indicated.

	2002		2001	
	High	Low	High	Low
First Quarter	$3.97	$2.36	$5.97	$3.38
Second Quarter	$5.35	$3.42	$4.62	$3.25
Third Quarter	$4.80	$3.10	$5.11	$2.50
Fourth Quarter	$5.00	$3.30	$3.48	$2.28

The closing market price of our common stock on March 21, 2003 was $4.69 per share. As of March 21, 2003, there were an estimated 114 record owners of our common stock.

No dividends have been declared or paid on our common stock to date. We intend to retain all future earnings for the development of our business. Our senior credit facility and subordinated notes facility restrict our ability to pay dividends on our common stock.

We are obligated to pay dividends on our Series A and Series B preferred stock. At our option, these dividends may be paid in cash at a rate of 6% per annum or paid in kind through the issuance of additional shares of preferred stock in lieu of cash at a rate of 8% per annum. Our option to pay dividends in kind on our Series A preferred stock expires in October 2005 and March 2006. Our option to pay dividends in kind on our Series B preferred stock expires in December 2007. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Series A Preferred Stock" and "—Liquidity and Capital Resources—Series B Preferred Stock".

Securities Authorized for Issuance under Equity Compensation Plans

The following table includes information regarding our equity compensation plans as of the year ended December 31, 2002:

Plan category	Number of securities to be issued upon exercise of outstanding options	Weighted-average price of outstanding options	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders	1,782,135	$ 3.34	—
Equity compensation plans not approved by security holders	—	—	—
Total	1,782,135	$ 3.34	—

Recent Sales of Unregistered Securities

In December 2002, in a transaction exempted from registration under section 4(2) of the Securities Act of 1933, we issued 550,000 unregistered shares of our common stock to Shell Capital in exchange for Shell Capital's warrant position, including 1,250,000 warrants associated with our senior subordinated notes facility, and to terminate Shell Capital's right to convert $30 million of our senior credit facility into 5,480,769 shares of our common stock. We are required to register these shares under certain conditions as outlined in a registration rights agreement with Shell Capital dated December 20, 2002.

In December 2002, in a transaction exempted from registration under section 4(2) of the Securities Act of 1933, we issued CSFB Private Equity 500,000 shares of our Series B preferred stock with a stated value of $20.00 per share. Net proceeds from the offering were $9.4 million and were used to reduce borrowings under our senior credit facility and to fund our drilling program and working capital requirements. The Series B preferred stock has terms similar to our Series A preferred stock. We are required to pay dividends on our Series B preferred stock as discussed above. The Series B preferred stock can be redeemed at our option after December 2007 and is mandatorily redeemable in December 2012. In connection with the Series B preferred stock offering, we issued to CSFB Private Equity warrants to purchase 2,298,851 shares of our common stock at an exercise price of $4.35 per share. To exercise the warrants, CSFB Private Equity has the option to use either cash or shares of our Series B preferred stock with an aggregate value equal to the exercise price. In the event that our stock price averages at least $6.525 for 60 consecutive trading days, then the warrants must be exercised if we so require. For financial reporting purposes, the warrants issued with the Series B preferred stock were valued at approximately $4.6 using the Black Scholes Option Pricing model and were recorded as additional paid in capital in December 2002.

ITEM 6. SELECTED FINANCIAL DATA

The following selected consolidated financial data should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and related notes included in "Item 8. Financial Statements and Supplementary Data."

	2002	2001	2000	1999	1998
		(in thousands, except per share data)			
Statement of Operations Data:					
Revenues:					
Oil and natural gas sales	$35,100	$ 32,293	$19,143	$ 14,992	$ 13,799
Other revenue	76	255	69	285	390
Total revenues	35,176	32,548	19,212	15,277	14,189
Costs and expenses:					
Lease operating	3,759	3,486	2,139	2,259	2,172
Production taxes	1,977	1,511	1,786	968	850
General and administrative	4,971	3,638	3,100	3,481	4,672
Depletion of oil and natural gas properties	14,594	13,211	7,920	7,792	8,483
Depreciation and amortization	440	677	620	526	785
Capitalized ceiling impairment	—	—	—	—	25,926
Total costs and expenses	25,741	22,523	15,565	15,026	42,888
Operating income (loss)	9,435	10,025	3,647	251	(28,699)
Other income (expense):					
Interest expense	(6,238)	(6,681)	(9,906)	(9,697)	(5,968)
Interest income	119	264	108	176	136
Debt conversion expense	(630)	—	—	—	—
Other income (expense)	(310)	8,080	(9,504)	(163)	—
Loss on sale of oil and natural gas properties	—	—	—	(12,195)	—
Total other income (expense)	(7,059)	1,663	(19,302)	(21,879)	(5,832)
Income (loss) before income taxes and extraordinary item	2,376	11,688	(15,655)	(21,628)	(34,531)
Income tax benefit (expense)	—	—	—	—	1,186
Income (loss) before extraordinary item	2,376	11,688	(15,655)	(21,628)	(33,345)
Extraordinary item—gain on refinancing of debt, net of tax	—	—	32,267	—	—
Net income (loss)	2,376	11,688	16,612	(21,628)	(33,345)
Preferred dividend and accretion	2,952	2,450	275	—	—
Net income (loss) available to common stockholders	$ (576)	$ 9,238	$16,337	$(21,628)	$(33,345)
Net income (loss) per share—basic	$ (0.04)	$ 0.58	$ 1.01	$ (1.53)	$ (2.64)
		Restated(1)			
Net income (loss) per share—diluted	(0.04)	0.44	1.01	(1.53)	(2.64)
Weighted average shares outstanding—basic	16,138	15,988	16,241	14,152	12,626
Weighted average shares outstanding—diluted	16,138	28,205	16,241	14,152	12,626
Statement of Cash Flows Data:					
Net cash provided (used) by operating activities	$28,973	$ 18,922	$ (4,635)	$ 2,578	$ 14,774
Net cash provided (used) by investing activities	(27,206)	(33,571)	(26,071)	1,644	(86,227)
Net cash provided (used) by financing activities	8,439	18,924	28,801	(4,049)	72,321
Other Financial Data:					
Oil and natural gas capital expenditures	$27,696	$ 34,532	$28,910	$ 25,560	$ 85,207

	As of December 31,				
	2002	*2001*	*2000*	*1999*	*1998*
Balance Sheet Data:					
Cash and cash equivalents	$15,318	$ 5,112	$ 837	$ 2,742	$ 2,569
Oil and natural gas properties, net	164,980	151,891	129,490	112,066	134,317
Total assets	202,059	173,075	146,911	125,683	150,516
Long-term debt	81,797	91,721	82,000	97,341	94,786
Series A Preferred Stock	19,540	16,614	8,558	—	—
Series B Preferred Stock	4,777	—	—	—	—
Total stockholders' equity	61,749	49,601	34,757	8,998	24,681

(1) Diluted net income per share for 2001 has been restated from that as previously reported. Refer to Note 10 of the Consolidated Financial Statements.

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

Statements in the following discussion may be forward-looking and involve risk and uncertainty. The following discussion should be read in conjunction with our Consolidated Financial Statements and Notes hereto.

From 1990 to 1996 we acquired 3-D seismic data in 28 plays, seven basins and seven states. In 1997 and 1998 we invested $64 million on 3-D seismic data and acreage in selected plays where we were experiencing attractive 3-D delineated drilling economics and repeatability. In 1999, we modified our business strategy to recognize the inherent value of our 3-D delineated prospect inventory and to provide significant improvement in our financial and operating results. This business strategy includes the following elements:

- Focus the majority of capital resources in our five focus plays to generate growth in proved reserves, production volumes and cash flow.
- Continue to grow our inventory of high potential exploration prospects through our technical staff's internal generation of such prospects.
- Enhance our project returns by attempting to retain operational control over all phases of our exploration and development activities.
- Allocate a higher percentage of drilling capital toward the development of our prior discoveries.
- Accelerate the development of our exploration and development prospect inventory by increasing our drilling expenditures.
- Enhance our return on capital and our cash margins by growing production, resulting in reduced per unit discretionary cash costs.

As a result of this strategy, we have accomplished the following for the three-year period ended December 31, 2002:

- An increase in our net proved reserves from 95 Bcfe to 121 Bcfe, a compound annual growth rate of 13%.
- An increase in our average daily production volumes from 18.3 Mmcfed to 27.8 Mmcfed, a compound annual growth rate of 23%.
- An increase in our EBITDA, from $12.0 million to $24.6 million, representing a compound annual growth rate of 43%. An increase in our revenues from $19.2 million to $35.2 million, a compound annual growth rate of 35%. See "—Other Matters—Reconciliation of Non-GAAP Measures".
- An all sources finding cost for the three-year period ended December 31, 2002 of $1.31 per Mcfe.

Recent Developments

In December 2002, we entered into a series of transactions whereby a number of warrants and convertible debt rights were extinguished or converted. We issued 550,000 unregistered shares of our common stock to Shell Capital in exchange for Shell Capital's warrant position and to terminate Shell Capital's right to convert $30 million of our senior credit facility into shares of our common stock. Also, DLJ Merchant Banking Partners III, L.P. in conjunction with GlobalEnergy Partners, both affiliates of CSFB Private Equity, purchased $10 million of our senior credit facility from Shall Capital and converted it into 2,564,102 shares of our common stock at an exercise price of $3.90 per share. We recorded $630,000 in debt conversion expenses associated with this conversion.

In December 2002, we issued CSFB Private Equity 500,000 shares of our Series B preferred stock with a stated value of $20.00 per share. Net proceeds from the offering were $9.4 million and were used to reduce borrowings under our senior credit facility and to fund our drilling program and working capital requirements. The Series B preferred stock has terms similar to our Series A preferred stock. We are required to pay dividends on our Series B preferred stock. At our option, these dividends may be paid in cash at a rate of 6% per annum or paid in kind through the issuance of additional shares of preferred stock in lieu of cash at a rate of 8% per annum. Our option to pay dividends in kind on our Series B preferred stock expires in December 2007. In connection with the Series B preferred stock offering, we issued to CSFB Private Equity warrants to purchase 2,298,851 shares of our common stock at an exercise price of $4.35 per share. To exercise the warrants, CSFB has the option to use either cash or shares of our Series B preferred stock with an aggregate value equal to the exercise price. In the event that our stock price averages at least $6.525 for 60 consecutive trading days, then the warrants must be exercised if we so require.

In December 2002, we extended the maturity on our senior credit facility by one year to December 2004 and extended our option to pay interest in kind on our senior subordinated notes facility by one year to October 2003.

In March 2003, we replaced our senior credit facility with a new senior credit facility. The new senior credit facility provides for a maximum commitment of $80 million in the form of a revolving bank credit facility, has an initial borrowing base of $70 million and matures in March 2006. As of the closing date of the facility, we had $56 million in outstanding borrowings under the new senior credit facility. See "—Liquidity and Capital Resources—Senior Credit Facility".

Critical Accounting Policies

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment to the specific set of circumstances existing in our business. Compliance with the rules necessarily involves reducing a number of very subjective judgments to a quantifiable accounting entry or valuation. We make every effort to properly comply with all applicable rules on or before their adoption, and we believe the proper implementation and consistent application of the accounting rules is critical. Our critical accounting policies are discussed below.

Property and Equipment

The method of accounting for oil and gas properties is a critical accounting policy because it determines what costs are capitalized, and how these costs are ultimately matched with revenues and expensed.

We use the full cost method of accounting for oil and properties. Under this method substantially all costs associated with oil and gas exploration and development activities are capitalized, including costs for individual exploration projects that do not directly result in the discovery of hydrocarbon reserves that can be economically recovered. Payroll, interest, and other internal costs we incur for the purpose of finding hydrocarbon reserves are also capitalized.

Full cost pool amounts associated with properties that have been evaluated through drilling or seismic analysis are depleted using the units of production method. The depletion expense per unit of production is the ratio of historical and estimated future development costs to hydrocarbon reserve volumes. Estimation of hydrocarbon reserves relies on professional judgment and use of factors that cannot be precisely determined. Reserve estimates materially different from those reported would change the depletion expense recognized during the reporting period. For the year ended December 31, 2002, our depletion expense per unit of production was $1.46 per Mcfe. A change of 900,000 Mcfe in our estimated net proved reserves at December 31, 2002, would result in a $0.01 per Mcfe change in our per unit depletion expense and a $100,000 change in net income available to common shareholders.

To the extent costs capitalized in the full-cost pool (net of depreciation, depletion and amortization and related deferred taxes) exceed the present value (using a 10% discount rate and based on period-end oil and natural gas prices) of estimated future net revenues from proved oil and natural gas reserves plus the capitalized cost of unproved properties, such costs are charged to operations as a reduction of the carrying value of oil and natural gas properties, or a "capitalized ceiling impairment" charge. The risk that we will be required to write down the carrying value of our oil and gas properties increases when oil and gas prices are depressed, even if the low prices are temporary. In addition, capitalized ceiling impairment charges may occur if we experience poor drilling results or estimations of proved reserves are substantially reduced.

A capitalized ceiling impairment is a reduction in earnings that does not impact cash flows, but does impact operating income and stockholders' equity. Once recognized, a capitalized ceiling impairment charge to oil and natural gas properties cannot be reversed at a later date. No assurance can be given that we will not experience a capitalized ceiling impairment charge in future periods. In addition, capitalized ceiling impairment charges may occur if estimates of proved hydrocarbon reserves are substantially reduced or estimates of future development costs increase significantly. See "—Risk Factors—Exploratory Drilling Is A Speculative Activity Involving Numerous Risks And Uncertain Costs; We are Dependent On Exloratory Drilling Activities", "—Risk Factors—Maintaining Reserves And Revenues In The Future Depends On Successful Exploration And Development" and "—Risk Factors—We Are Subject To Uncertainties In Reserve Estimates and Futures Net Cash Flows".

Income Taxes

Deferred tax assets are recognized for temporary differences in financial statement and tax basis amounts that will result in deductible amounts and carry-forwards in future years. Deferred tax liabilities are recognized for temporary differences that will result in taxable amounts in future years. Deferred tax assets and liabilities are measured using enacted tax law and tax rate(s) for the year in which we expect the temporary differences to be deducted or settled. The effect of a change in tax law or rates on the valuation of deferred tax assets and liabilities is recognized in income in the period of enactment. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Estimating the amount of the valuation allowance is dependent on estimates of future taxable income, alternative minimum tax income, and changes in shareholder ownership which would trigger limits on use of net operating losses under Internal Revenue Code Section 382.

Revenue Recognition

Because revenue is a key component of our results of operations, and we derive revenue primarily from the sale of produced oil and gas, our revenue recognition for these sales is significant.

We recognize crude oil revenue using the sales method of accounting. Under this method, we recognize revenue when oil is delivered and title transfers.

We recognize natural gas revenue using the entitlements method of accounting. Under this method, revenue is recognized based on our entitled ownership percentage of sales of natural gas to purchasers. Gas imbalances occur when we sell more or less than our entitled ownership percentage of total natural gas production. When we receive less than our entitled share, a receivable is recorded. When we receive more than our entitled share, a liability is recorded.

Settlements for hydrocarbon sales can occur up to two months after the end of the month in which the oil, gas or other hydrocarbon products were produced. We estimate and accrue for the value of these sales using information available at the time financial statements are generated. Differences are reflected in the accounting period that payments are received from the purchaser. For the month of December 2002 a $0.10 change in the price per Mcf of gas sold would change revenue by $50,000. A $0.70 change in the price per barrel of oil would change revenue by $50,000.

Derivative Instruments and Hedging Activities

We use derivative instruments to manage market risks resulting from fluctuations in commodity prices of natural gas and crude oil. We periodically enter into commodity contracts, including price swaps, caps and floors, which require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a fixed quantity of natural gas or crude oil without the exchange of underlying volumes. The notional amounts of these financial instruments are based on expected production from existing wells.

We adopted Statement of Financial Accounting Standards No. 133 on January 1, 2001 in accordance with Financial Accounting Standards Board requirements. SFAS No. 133, as amended, establishes accounting and reporting standards for derivative instruments and for hedging activities. All derivative instruments are recorded on the balance sheet at fair value and changes in the fair value of the derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction, and depending on the type of hedge transaction. Our derivative contracts consist primarily of cash flow hedge transactions in which we are hedging the variability of cash flow related to a forecasted transaction. Change in the fair value of these derivative instruments are reported in other comprehensive income and reclassified as earnings in the period(s) in which earnings are impacted by the variability of the cash flow of the hedged item. We assess the effectiveness of hedging transactions every three months, consistent with documented risk management strategy for the particular hedging relationship. Changes in fair value of ineffective hedges are included in earnings.

Use of Estimates

The preparation of financial statements in accordance with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect reported assets, liabilities, revenues, expenses, and some narrative disclosures. Hydrocarbon reserve, future development costs, and certain hydrocarbon production expense and revenue estimates are the most critical to our financial statements.

New Accounting Pronouncements

In June 2001, the Financial Accounting Standards Board issued Statement of Financial Standards No. 143, "Asset Retirement Obligations" which establishes accounting requirements for retirement obligations associated with tangible long-lived assets including the timing of the liability recognition, initial measurement of the liability, allocation of asset retirement cost to expense, subsequent measurement of the liability and financial statement disclosures. SFAS 143 requires that an asset retirement cost be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic, rational method. We adopted this standard as required on January 1, 2003. We are currently evaluating the effect of this statement on our consolidated financial position, results of operations and cash flows.

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB statements No. 4, 44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections". SFAS 145 requires, except in the case of events or transactions of a highly unusual and infrequent nature, gains or losses from the early extinguishment of debt to be classified as components of a company's income or loss from continuing operations. Prior to the adoption of the provisions of SFAS 145, gains or losses on the early extinguishment of debt were required to be classified in a company's periodic consolidated statements of operations as extraordinary gains or losses, net of associated income taxes, after the determination of income or loss from continuing operations. SFAS No. 145 is effective for fiscal years beginning after May 15, 2002. Due to the requirements of SFAS No. 145, it is less likely that a gain or loss on extinguishment of debt would be classified as an extraordinary item in our results of operations.

Off Balance Sheet Arrangements

We do not currently have any off-balance sheet arrangements or other such unrecorded obligations and we have not guaranteed the debt of any other party.

Commodity Pricing

Changes in commodity prices significantly affect our capital resources, liquidity and expected operating results. Price changes directly affect revenues and can indirectly impact expected production by changing the amount of funds available to reinvest in exploration and development activities. The prices we receive for our crude oil production are based on global market conditions. The price we receive for our natural gas production is primarily driven by North American market forces. Oil and gas prices have fluctuated significantly in recent years in response to numerous economic, political and environmental factors. The year 2002 began with a weakened commodity environment and lower prices. However, prices were on an upward trend through the year. Prices are also affected by weather, factors of supply and demand, and commodity inventory levels. During 2002, the high and low settlement prices for oil on the NYMEX were $32.72 per Bbl and $17.97 per Bbl, and the high and low settlement prices for natural gas on the NYMEX were $5.34 per MMBtu and $1.91 per MMBtu. We expect that commodity prices will continue to fluctuate significantly in the future.

Results of Operations

The following table sets forth certain operating data for the periods presented.

	Year Ended December 31,		
	2002	2001	2000
Production (in thousands):			
Natural gas (MMcf)	5,791	6,766	4,431
Oil (MBbls)	701	468	362
Natural gas equivalent (MMcfe)	9,996	9,573	6,600
% Natural gas	58%	71%	67%
Average sales prices per unit (After hedging)			
Natural gas (per Mcf)	$3.21	$3.11	$1.94
Oil (per Bbl)	23.55	24.05	29.17
Natural gas equivalent (per Mcfe)	3.51	3.37	2.90
Costs and expenses per Mcfe:			
Lease operating	$0.38	$0.36	$0.32
Production taxes	0.20	0.16	0.27
General and administrative	0.50	0.38	0.47
Depletion of oil and natural gas properties	1.46	1.38	1.20

Overview

For the year ended December 31, 2002, we had a net loss to common stockholders of $576,000, or $0.04 per diluted share, on total revenues of $35.2 million compared to net income of $9.2 million, or $0.44 per diluted share (as restated, refer to Note 10 to the Consolidated Financial Statements) on revenue of $32.5 million for the year ended December 31, 2001, and net income of $16.3 million, or $1.01 per diluted share, on revenue of $19.2 million for the year ended December 31, 2000. Net income in 2002 included $384,000 in non-cash gains related to changes in the fair-market value of derivative contracts that did not qualify for hedge accounting treatment. This non-cash gain was partially offset by a $121,000 non-cash loss for ineffective hedging transactions. Net income in 2001 was significantly enhanced by $9.7 million in non-cash gains related to changes in the fair-market value of derivative contracts that did not qualify for hedge accounting treatment. Net income in 2000 was significantly enhanced by a $32.3 million extraordinary gain on the refinancing of our senior subordinated debt and was partially offset by a non-cash loss of $8.9 million related to changes in the fair-market value of derivative contracts that did not qualify for hedge accounting treatment.

Production. Net equivalent production volumes for 2002 were 10.0 Bcfe compared to 9.6 Bcfe in 2001 and 6.6 Bcfe in 2000. Average net daily equivalent production volumes for 2002 were 27.8 MMcfed, compared to 26.6 MMcfed in 2001 and 18.3 MMcfed in 2000. The increase in production from 2000 through 2002 is due to organic production growth during the period. Additional production related to wells completed during the period was partially offset by the natural decline of existing production. Natural gas production represented 58% of our total production volume on an equivalent basis in 2002 compared to 71% in 2001 and 67% in 2000.

Revenue from the sale of oil and natural gas. Revenue from the sale of oil and natural gas for 2002 was $35.1 million compared to $32.3 million in 2001 and $19.1 million in 2000.

For 2002 compared to 2001, revenue from the sale of oil and natural gas was up $2.8 million or 9%. A 4% increase in our total production volume accounted for $2.6 million of this change and a $0.14 per Mcfe increase in our average realized sales price for oil and natural gas accounted for $232,000 of this change. Revenue from the sale of oil and natural gas in 2002 included a loss of $1.8 million, or $0.19 per Mcfe, related to cash settlements on hedging transactions, compared to a loss of $8.2 million, or $0.85 per Mcfe, in 2001. Our average realized sales price for oil and natural gas in 2002 was $3.51 per Mcfe compared to $3.37 per Mcfe in 2001.

For 2001 compared to 2000, revenue from the sale of oil and natural gas was up $13.2 million or 69%. A 45% increase in our total production volume accounted for $7.7 million of this change and a $0.47 per Mcfe increase in our average realized sales price for oil and natural gas accounted for $5.5 million of this change. Revenue from the sale of oil and natural gas in 2001 included a loss of $8.2 million, or $0.85 per Mcfe, related to cash settlements on hedging transactions, compared to a loss of $9.5 million, or $1.44 per Mcfe, in 2000. Our average realized sales price for oil and natural gas in 2001 was $3.37 per Mcfe compared to $2.90 per Mcfe in 2000.

Other revenue. Other revenue was $76,000 in 2002, compared to $255,000 in 2001 and $69,000 in 2000. This revenue relates to billings to other parties for gathering services.

Lease operating expenses. Lease operating expenses, which includes lifting cost and ad valorem taxes, for 2002 were $3.8 million compared to $3.5 million in 2001 and $2.1 million in 2000.

	2002	2001	2000
		(in thousands)	
Lease operating expense, excluding ad valorem taxes	$3,148	$3,015	$1,886
Ad valorem taxes	611	471	253
Total lease operating expenses	$3,759	$3,486	$2,139
		($ per Mcfe)	
Lease operating expense per unit of production:			
Lease operating expense, excluding ad valorem taxes	$ 0.32	$ 0.31	$ 0.28
Ad valorem taxes	0.06	0.05	0.04
Total lease operating expenses	$ 0.38	$ 0.36	$ 0.32

For 2002 compared to 2001, total lease operating expenses increased 8%. On a per unit of equivalent production basis, lease operating expenses for 2002 were $0.38 per Mcfe, compared to $0.36 per Mcfe in 2001. The change in our lease operating expense was primarily the result of higher ad valorem taxes due to an increase in property valuations because of higher average commodity prices during 2001 and higher overall service cost.

For 2001 compared to 2000, total lease operating expenses increased 63%. The change in lease operating expenses is primarily due to an increase in the number of producing wells. Lease operating expenses on a per unit of production in 2001 were $0.36 per Mcfe compared to $0.32 per Mcfe in 2000. The increase in our per unit lease operating expense was primarily due to higher overall service cost and higher ad valorem taxes due to an increase in property valuations because of higher average commodity prices during 2000.

Production taxes. Production taxes for 2002 were $2.0 million compared to $1.5 million in 2001 and $1.8 million in 2000.

For 2002 compared to 2001, the increase in production taxes was primarily due to a reduction in the number of wells that qualify for severance tax refunds in 2002. Our effective production tax rate in 2002 was 5.4% of pre-hedge oil and natural gas sales revenue, compared to 3.7% in 2001.

For 2001 compared to 2000, the decrease in production taxes was primarily related to production tax refunds on wells that qualify for reduced severance tax rates. Our effective production tax rate in 2001 was 3.7% of pre-hedge oil and natural gas sales revenue, compared to 6.2% in 2000.

General and administrative expenses. General and administrative expenses for 2002 were $5.0 million, compared to $3.6 million in 2001 and $3.1 million in 2000.

For 2002 compared to 2001, the increase in general and administrative expenses included a non-recurring charge for non-cash compensation expense of $596,000 related to vesting of options by an officer who left the company. Excluding this non-cash charge, general and administrative expenses for 2002 increased 20% to $4.4 million. Other items contributing to the increase in general and administrative expenses include the cost associated with bringing our oil and natural gas marketing activities in house, increased payroll and benefit expense, higher office rent expense, higher other office expenses and an increase in corporate insurance expense.

For 2001 compared to 2000, general and administrative expenses increased 17%. This increase was primarily due to an increase in employee payroll and benefit expense, office expense, public company expense and contract and professional expense.

Depletion of oil and natural gas properties. Depletion of oil and natural gas properties in 2002 was $14.6 million compared to $13.2 million in 2001 and $7.9 million in 2000.

For 2002 compared to 2001, a $0.08 increase in our depletion rate accounted for $800,000 of the change and higher production volumes accounted for $584,000 of the change. This increase in our per unit depletion expense was due to additional future development cost related to our Floyd Fault Block Field discovery.

For 2001 compared to 2000, depletion expense increased $5.3 million. Increased production volumes accounted for $4.1 million of this increase and a $0.18 increase in our depletion rate accounted for a $1.2 million of the increase. The increase in the depletion rate per unit is primarily due to an increase in the estimated cost required to fully develop our Home Run Field.

Net interest expense. Net interest expense for 2002 was $6.2 million compared to $6.7 million in 2001 and $9.9 million in 2000.

	2002	2001	2000
		(in thousands)	
Interest on outstanding indebtedness(1)	$ 5,878	$ 7,081	$10,327
Commitment fees	3	29	43
Amortization of deferred loan and debt issuance cost	1,191	1,372	1,283
Amortization of debt discount	—	—	673
Other general interest expense	44	47	352
Capitalized interest expense	(878)	(1,848)	(2,772)
Net interest expense	$ 6,238	$ 6,681	$ 9,906
Weighted average debt outstanding	$95,562	$90,646	$97,424
Average interest rate on outstanding indebtedness(2)	6.2%	7.8%	10.6%

(1) Includes $1.1 million, $721,000 and $4.6 million in interest expense on our subordinated notes that was paid in kind through the issuance of additional debt in lieu of cash, for 2002, 2001 and 2000, respectively.

(2) Calculated as the sum of interest expense on outstanding indebtedness and commitment fees divided by weighted average debt outstanding for the period.

For 2002 compared to 2001, the change in net interest expense was primarily due to a lower average interest rate on outstanding indebtedness during 2002 and to a lesser extent on a decrease in the amount of deferred loan fees amortized. The change in the average interest rate on our outstanding borrowings was due to a decrease in the London Interbank Offered Rate (LIBOR), which is used to determine the interest rate on borrowings outstanding under our senior credit facility. The average interest rate on borrowings outstanding under our senior credit facility during 2002 was 5.0% compared to 7.2% in 2001. At December 31, 2002, the interest rate on borrowings outstanding under our senior credit facility was 4.5%.

For 2001 compared to 2000, the change in net interest expense was primarily due to a lower weighted average outstanding debt balance and a lower average interest rate on our outstanding borrowings during 2001. The repurchase of $51.2 million in subordinated notes in November 2000 that bore annual interest rates of 12% to 14% was the primary reason the for the decrease in our weighted average debt balance and lower average interest rate in 2001. A decrease in the average interest rate on borrowings outstanding under our senior credit facility due to a lower London Interbank Offered Rate (LIBOR) during also contributed to the decrease in our average interest rate.

Other income (expense). Other income (expense) in 2002 was an expense of $310,000 compared to $8.1 million in income in 2001 and $9.5 million in expense in 2000. Other income (expense) consists primarily of items related to the change in the fair market value and the related cash flows of certain oil and natural gas derivative contracts that do not qualify for hedge accounting treatment. Other income (expense) in 2002 included (i) $384,000 in non-cash income related to the change in the fair market value of derivative contracts during the period that did not qualify for hedge accounting treatment, (ii) $121,000 in non-cash expense related to the ineffective portion of hedging transactions, and (iii) $559,000 of expenses related to cash settlements on derivative contracts that did not qualify for hedge accounting treatment. Other income (expense) in 2001 included (i) $9.7 million of non-cash income related to the change in the fair market value of derivative contracts during the period, and (ii) $1.5 million of expenses related to cash settlements on derivative contracts that did not qualify for hedge accounting treatment. Other income (expense) in 2000 included (i) $8.9 million of non-cash expense related to the change in the fair market value of derivative contracts during the period, and (ii) $620,000 of expenses related to cash settlements on derivative contracts that did not qualify for hedge accounting treatment.

Debt Conversion expense. Debt conversion expense of $630,000 represents the costs and fees we incurred to execute the conversion of $10 million of our senior debt to common stock. Our total outstanding indebtedness at December 31, 2002 was $81.8 million, compared to $91.7 million at December 31, 2001. There were no similar expenses in prior periods.

Extraordinary gain on refinancing of senior subordinated notes. In November 2000, we repurchased all of our debt and equity securities held by affiliates of Enron North America at a substantial discount. With a portion of the proceeds from two new financing transactions, we repurchased all of the Enron Affiliates' interests, which included (i) $51.2 million of senior subordinated notes due 2003 (which bore interest at annual rates of 12% to 14%) and associated accrued interest obligations, (ii) warrants to purchase an aggregate of one million shares of our common stock at $2.43 per share, and (iii) 1,052,632 shares of common stock, for total cash consideration of $20 million. As a result of the repurchase of the senior subordinated notes due 2003 at a discount to the principal amount outstanding, we recorded an extraordinary gain of $32.3 million in the fourth quarter of 2000. There were no similar items during 2002 or 2001.

Liquidity and Capital Resources

Our primary sources of capital have been funds generated by operations, our senior credit and subordinated notes facility, public and private equity financings and the sale of interests in projects and properties. Our level of earnings and cash flows depends on market prices that we receive for our oil and natural gas production, our ability to find and produce hydrocarbons and our ability to control and reduce cost.

Our primary sources of cash during 2002 were funds generated from operations, proceeds from the sale of our Series B preferred stock and borrowings under our subordinated notes facility. Funds were used primarily for costs associated with drilling, land acquisition and 3-D seismic acquisition, processing and interpretation and to reduce the level of borrowings under our senior credit facility.

Cash Flows Provided (Used) By Operating Activities

	2002	2001	2000
		(in thousands)	
Operating cash flow before changes in working capital	$20,010	$18,097	$ 8,581
Changes in working capital	8,963	825	$(13,216)
Net cash flow provided (used) by operating activities	$28,973	$18,922	$ (4,635)

For 2002 compared to 2001, cash flows provided by operating activities increased by $10.0 million. This change included a $1.9 million increase in cash flow provided by operating activities before changes in working capital and an $8.1 million increase in cash flow from changes in working capital activities. The change in cash flow provided by operating activities (exclusive of changes in working capital) was due to an increase in revenue from the sale of oil and natural gas, a decrease in cash interest expense and a decrease in cash settlements on derivatives that do not qualify for hedging activities. These changes were partially offset by increases in our lease operating expense, production taxes, cash general and administrative expense and debt conversion cost.

For 2001 compared to 2000, cash flows provided by operating activities increased by $23.6 million. This change included a $9.5 million (exclusive of changes in working capital) increase. This increase is due to an increase in revenue from the sale of oil and natural gas which was partially offset by an increase in lease operating expense, cash general and administrative expenses, cash interest expense and increase in cash losses on the settlement of derivative contracts that do not qualify for hedge accounting treatment.

Cash Flows Used By Investing Activities

	2002	2001	2000
		(in thousands)	
Net cash flow used by investing activities	$27,206	$33,571	$26,071

Our primary capital requirements are for cost associated with drilling, land acquisition and 3-D seismic acquisition, processing and interpretation. Our initial capital budget at the start of 2002 was projected to be $23.7 million and was down 33% when compared to capital expenditures in 2001. Due to lower forecasted oil and natural gas prices at the time, the reduced capital expenditure program reflected our desire to fund our capital expenditure program with cash flow generated from operations, cash on hand at the start of the year and availability under our senior subordinated notes facility. As the year progressed, we increased our capital budget to partially account for the increase in commodity prices.

For 2002 compared to 2001, cash flows used by investing activities decreased 19%. This change is primarily due to a reduction in capital spending on oil and gas properties.

For 2001 compared to 2000, cash flows used by investing activities increased 29%. This change is primarily due to an increase in capital spending on oil and gas activities.

Cash Flows Provided By Financing Activities

	2002	2001	2000
		(in thousands)	
Net cash flow provided by financing activities	$8,439	$18,924	$28,801

Over the past three years, we have reduced our reliance on external sources to fund our capital expenditure programs. For 2002, net cash flow provided by financing activities decreased by $10.5 million compared to 2001 and by $20.4 million when compared to 2000. The decrease in our reliance on external sources to fund our capital expenditures has primarily been the result of an increase in the cash flow generated by our operating activities and reduced capital spending.

In 2002, cash inflows from financing activities included $4.0 million of additional borrowing under subordinated notes facility, $9.4 million in net proceeds from the issuance of $10 million in Series B preferred stock and warrants to purchase our common stock and $921,000 in proceeds from the exercise of options and warrants that resulted in the issuance of 376,409 shares of our common stock. These inflows were partially offset by the repayment of $5.0 million of outstanding indebtedness under our senior credit facility and debt issue cost of $0.6 million. The remainder of the cash inflows will be used to fund our capital expenditures, fund working capital obligations and repay outstanding indebtedness under our senior credit facility.

In 2001, cash inflows from financing activities included $9.0 million of additional borrowing under our subordinated notes facility, $9.8 million of net proceeds from the issuance of $10 million in Series A preferred stock and warrants to purchase of our common stock and $252,000 in proceeds from the exercise of options that resulted in the issuance of 97,474 shares of our common stock. These cash inflows were used to fund capital expenditures and working capital obligations.

During 2000, cash inflows from financing activities included $19.0 million in additional borrowings under our senior credit facility, $7.0 million of borrowing under subordinated notes facility, $20.1 million in net proceeds from the issuance of $20.0 million in Series A preferred stock and warrants to purchase of our common stock, $4.2 million in net proceeds from the sale of 2.2 million shares of our common stock and the payment of $902,000 in loan cost. These inflows were partially offset by our purchase of $51.2 million of our outstanding subordinated notes and associated accrued interest, warrants to purchase one million shares of common stock at $2.43 per share and 1.1 million shares of our common stock, for total cash consideration of $20.0 million. The remainder of the net proceeds were used to fund capital expenditures and working capital obligations.

Senior Credit Facility

At December 31, 2002, we had $60.0 million of indebtedness outstanding under our senior credit facility. In December 2002, DLJ Merchant Banking Partners III, L.P. in conjunction with GlobalEnergy Partners, affiliates of CSFB Private Equity, purchased $10 million of our senior credit from Shell Capital and converted it into 2,564,102 shares of our common stock, at an exercise price of $3.90 per share. We also used $5.0 million of the net proceeds from the issuance of Series B preferred stock and warrants to repay indebtedness outstanding under our senior credit facility. The credit facility agreement contains various covenants and restrictive provisions which limit our capital spending on land and seismic, ability to incur additional indebtedness, sell properties, pay dividends, purchase or redeem our capital stock, make investments or loans, create liens and make certain acquisitions. The senior credit facility requires us to maintain a current ratio (as defined) of at least 1 to 1 and an interest coverage ratio (as defined) of at least 2.5 to 1. Our current ratio at December 31, 2002 and interest coverage ratio for the twelve-month period ending December 31, 2002, were 1.3 to 1 and 3.4 to 1, respectively. In December 2002, the maturity on our senior credit facility was extended by one year to December 31, 2004.

In March 2003, we replaced our senior credit facility with a new senior credit facility that provides for a maximum $80 million in commitments and an initial borrowing base of $70 million and matures in March 2006. Borrowings under the new credit facility are secured by substantially all of our oil and natural gas properties and other tangible assets and bear interest at either the base rate of Société Générale or London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies according to facility usage. Interest is paid quarterly. The collateral value and borrowing base are redetermined periodically. The unused portion of the committed borrowing base is subject to an annual commitment fee of 0.5%. As of March 21, 2003, we had $56 million of borrowings outstanding and $14 million in additional borrowing capacity under our new senior credit facility.

The new senior credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, sell properties, purchase or redeem our capital stock, make investments or loans, create liens and make certain acquisitions. The new senior credit facility requires us to maintain a current ratio (as defined) of at least 1 to 1 and an interest coverage ratio (as defined) of at least 3.25 to 1. Should we be unable to comply with these or other covenants, our senior lenders may be unwilling to waive compliance or amend the covenants in the future. In such instance, our liquidity may be adversely affected, which could in turn have an adverse impact on our future financial position and results of operations. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable.

Senior Subordinated Notes

As of December 31, 2002, we had $21.8 million of senior subordinated notes outstanding. The notes bear interest at 10.75% per annum, payable quarterly in arrears on the last day of January, April, July and October, are redeemable at our option for face value at any time and have no principal repayment obligations until maturity in October 2005. At our option, up to 50% of the interest payments on the senior subordinated notes can be satisfied by payment in kind through the issuance of additional senior subordinated notes in lieu of cash. In December 2002, as part of the exchange of our common stock for warrants and debt conversion rights held by Shell Capital, we extended our option to satisfy 50% of our interest obligation through the issuance of additional subordinated notes through October 2003. For the year ended December 31, 2002, we exercised this option and issued an additional $1.1 million in senior subordinated notes. As of March 21, 2003, we have exercised this option and have issued approximately $2.1 million in additional senior subordinated notes. As of March 21, 2003, we had $22.1 million of borrowings outstanding with no additional borrowing capacity under our senior subordinated notes facility.

The senior subordinated notes are issued pursuant to a senior subordinated notes facility dated October 31, 2000, which was amended and restated on March 21, 2003. Under the facility, Shell Capital agreed to provide up to $20 million (plus any amount of interest paid in kind) in senior subordinated notes in borrowing increments of at least $1 million. Once borrowings under the subordinated notes facility have been repaid, they cannot be withdrawn. The senior subordinated notes are secured obligations ranking junior to our new senior credit facility and have covenants similar to the new senior credit facility. Our current ratio at December 31, 2002 and interest coverage ratio for the twelve-month period ending December 31, 2002, were 1.3 to 1 and 3.4 to 1, respectively.

In October 2000, in connection with the senior subordinated notes facility, we issued warrants to purchase 1,250,000 shares of our common stock at an exercise price of $3.00 per share. Brigham valued the warrants using the Black-Scholes Option Pricing Model and recorded the estimated value of $2.9 million as deferred loan costs which are being amortized over the five-year term of the senior subordinated notes facility. In December 2002, as part of the exchange of our common stock for warrants and debt conversion rights held by Shell Capital, the warrants to purchase 1,250,000 shares of our common stock at $3.00 per share were extinguished.

Series A Preferred Stock

We have issued two tranches of mandatorily redeemable Series A preferred stock to CSFB Private Equity. The first tranche, $20 million, was issued in November 2000 and the second tranche,

$10 million, was issued March 2001. We are required to pay dividends on our Series A preferred stock. At our option, these dividends may be paid in cash at a rate of 6% per annum or paid in kind through the issuance of additional shares of preferred stock in lieu of cash at a rate of 8% per annum. Our option to pay dividends in kind on the first tranche expires in October 2005 and the second tranche expires in March 2006. To date, we have satisfied all of the dividend payments with issuance of additional shares of Series A preferred stock. The Series A preferred stock has a ten-year maturity and is redeemable at our option at 100% or 101% of the stated value per share (depending upon certain conditions) at anytime prior to maturity. As of March 21, 2003 the liquidation value of the Series A preferred stock was $35.9 million including accrued but unpaid dividends. Approximately $5.9 million of the liquidation value represents additional Series A preferred stock issued and accrued to satisfy our dividend payments.

In connection with the two tranches of Series A preferred stock, we issued to CSFB Private Equity warrants to purchase our common stock. With the first tranche we issued warrants to purchase 6,666,667 shares of our common stock at an exercise price of $3.00. With the second tranche we issued warrants to purchase 2,105,263 shares of our common stock at an exercise price of $4.75. In connection with the December 2002 Series B preferred stock and warrant offering (see Series B Preferred Stock below), the exercise price of the warrants originally issued with the second tranche of Series A preferred stock was reset to $4.35. To exercise the warrants, CSFB Private Equity has the option to use either cash or shares of our Series A preferred stock with an aggregate value equal to the exercise price.

Series B Preferred Stock

In December 2002, we issued CSFB Private Equity 500,000 shares of our Series B preferred stock with a stated value of $20.00 per share. Net proceeds from the offering were $9.4 million and were used to reduce borrowings under our senior credit facility and fund our drilling program and working capital requirements. The Series B preferred stock has terms similar to our Series A preferred stock. We are required to pay dividends on our Series B preferred stock. At our option, these dividends may be paid in cash at a rate of 6% per annum or paid in kind through the issuance of additional shares of preferred stock in lieu of cash at a rate of 8% per annum. Our option to pay dividends in kind on our Series B preferred stock expires in December 2007. The Series B preferred stock can be redeemed at our option after December 2007 and is mandatorily redeemable in December 2012.

As of March 21, 2003 the liquidation value of the Series B preferred stock was $10.2 million including accrued but unpaid dividends in kind. Approximately $0.2 million of the liquidation value represents additional Series B preferred stock issued and accrued to satisfy our dividend payments.

In connection with the Series B preferred stock offering, we issued to CSFB Private Equity warrants to purchase 2,298,851 shares of our common stock at an exercise price of $4.35 per share. To exercise the warrants, CSFB has the option to use either cash or shares of our Series B preferred stock with an aggregate value equal to the exercise price. In the event that our stock price averages at least $6.525 for 60 sixty consecutive trading days, then the warrants must be exercised if we so require. For financial reporting purposes, the warrants issued with the Series B preferred stock were valued at approximately $4.6 million using the Black Scholes Option Pricing model and were recorded as additional paid in capital in December 2002.

Capital Expenditures

	2002	2001	2000
		(in thousands)	
Drilling	$19,800	$27,209	$18,461
Land and G&G	3,751	2,750	4,585
Capitalized G&A and interest	5,657	6,050	6,300
Proceeds from participants and sales	(1,524)	(397)	(4,002)
Total capital expenditures on oil & gas properties	27,684	35,612	25,344
Other property and equipment	249	241	135
Total capital expenditures	$27,933	$35,853	$25,479

Our capital-spending budget for 2003 is $39.3 million. The majority of our planned 2003 expenditures will be directed towards drilling our prospect inventory in a continued effort to focus resources on our primary objective of growing production volumes and cash flow. For 2003, we expect to spend approximately $27.9 million to drill 41 wells with an average working interest of 36%. Capitalizing on the prior exploration successes at the Home Run, Mills Ranch, Triple Crown, Floyd Fault Block and Providence Fields, approximately 60% of our 2003 drilling expenditures are dedicated to development drilling. Spending will be funded by our operating cash flow, cash on hand at the start of the year and available capacity under our new senior credit facility. Capital expenditures for 2003 are expected to be up approximately 42% over 2002. This increase is primarily attributable to a more robust current and forecasted commodity price environment and to lesser degree our additional financial flexibility resulting from the CSFB Private Equity Financings completed in December 2002.

Actual capital spending may vary and is subject to changing market condition. The 2003 capital expenditure budget was developed using certain assumed price levels for the sales of crude oil and natural gas and forecasted production growth. Changes in commodity prices or variances from forecasted production growth could impact our cash flows from operations and funds available for reinvestment. For example, shortfalls in budgeted cash flows from operations could result in the reduction of the our capital spending program, increases in borrowing under our new senior credit facility, issuance of additional equity or debt securities or divestments of properties. We evaluate our level of capital spending throughout the year based upon drilling results, commodity prices and cash flows from operations.

Contractual Obligations

The following schedule summarizes our known contractual cash obligations at December 31, 2002 and the effect such obligations are expected to have on our liquidity and cash flow in future periods.

	Payments Due by Year				
	Total Outstanding	2003	2004-2005	2006-2007	Thereafter
Senior credit facility	$ 60,000	$ —	$60,000	$ —	$ —
Subordinated notes facility	21,797	—	21,797	—	—
Non-cancelable operating leases	3,983	885	1,770	1,328	—
Manditorily redeemable, Series A preferred stock(a)	35,303	—	—	—	35,303
Manditorily redeemable, Series B preferred stock(b)	10,025	—	—	—	10,025
Total Contractual Cash Obligations	$131,108	$885	$83,567	$1,328	$45,328

(a) CSFB Private Equity can use $29.2 million of this Series A preferred stock to pay the warrant exercise price to purchase 6,666,667 shares of our common stock for $3.00 per share and 2,105,263 shares of our common stock for $4.35 per share. If the price of our common stock trades above $5.00 per share for 60 consecutive trading days, we can require CSFB Private Equity to exercise the warrants to purchase 6,666,667 shares of our common stock for $3.00 per share. If the price of our common stock averages above $6.525 for 60 consecutive trading days, we can require CSFB Private Equity to exercise the warrants to purchase 2,105,263 shares of our common stock for $4.35 per share. If we require CSFB Private Equity to exercise either of these warrants, we will be required to use the proceeds from the exercise to retire Series A preferred stock. The Series A preferred stock is redeemable at our option at 100% or 101% of the stated value (depending upon certain conditions) at anytime prior to maturity.

(b) CSFB Private Equity can use $10.0 million of this Series B preferred stock to pay the warrant exercise price to purchase 2,298,851 shares of our common stock for for $4.35 per share. If the price of our common stock averages $6.525 for 60 consecutive trading days, we can require CSFB Private Equity to exercise the warrants to purchase 2,298,851 shares of our common stock for $4.35 per share. If we require CSFB Private Equity to exercise these warrants, we will be required to use the proceeds from the exercise to retire Series B preferred stock and we will be required to retire any Series B preferred that remains outstanding. The Series B preferred stock is redeemable at our option at 100% or 101% of the stated value (depending upon certain conditions) at anytime after December 2007.

Some of our commodity price risk management arrangements have required us to deliver cash collateral or other assurances of performance to the counterparties in the event that our payment obligations with respect to our commodity price risk management transactions exceed certain levels. At December 31, 2002, we were required to post $1.9 million in collateral. It is not anticipated that we will be required to post cash collateral with the new senior credit facility. However, future requirements are uncertain and will depend on arrangements with our counterparities and highly volatile oil and natural gas prices.

Other Matters

Reconciliation of Non-GAAP Measures

EBITDA is defined as net income (loss) plus interest expense, depletion, depreciation and amortization expenses, deferred income taxes and other non-cash items.

We believe that operating income is the financial measure calculated and presented in accordance with generally accepted accounting principles that is most directly comparable to EBITDA as defined. The following table reconciles EBITDA as defined with our operating income, as derived from our financial statements.

	2002	2001	2000
		(in thousands)	
Operating Income	$ 9,435	$10,025	$ 3,647
Depletion, depreciation and amortization	15,034	13,888	8,540
Non-cash compensation expense	596	—	—
Interest Income	119	264	108
Cash settlements on derivatives not qualifying for hedge accounting treatment	(559)	(1,492)	(620)
Amortization of deferred loss on derivative instruments	—	—	280
Cash portion of other income/(expense)	(14)	—	—
EBITDA	$24,611	$22,685	$11,955

Derivative Instruments

Our results of operations and operating cash flow are impacted by changes in market prices for oil and gas. We believe the use of derivative instruments, although not free of risk, allows us to reduce our exposure to oil and natural gas sales price fluctuations and thereby achieve a more predictable cash flow. While the use of derivative instruments limits the downside risk of adverse price movements, their use may also limit future revenues from favorable price movements. Moreover, our hedging arrangements generally do not apply to all of our production and thus provide only partial price protection against declines in commodity prices. We expect that the amount of our hedges will vary from time to time. See "—Risk Factors—Our Hedging Transactions May Not Prevent Losses" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk".

Effects of Inflation and Changes in Prices

Our results of operations and cash flows are affected by changing oil and natural gas prices. If the price of oil and natural gas increases (decreases), there could be a corresponding increase (decrease) in revenues as well as the operating costs that we are required to bear for operations. Inflation has had a minimal effect on us.

Environmental and Other Regulatory Matters

Our business is subject to certain federal, state and local laws and regulations relating to the exploration for and the development, production and marketing of oil and natural gas, as well as environmental and safety matters. Many of these laws and regulations have become more stringent in recent years, often imposing greater liability on a larger number of potentially responsible parties. Although we believe that we are in substantial compliance with all applicable laws and regulations, the requirements imposed by laws and regulations are frequently changed and subject to interpretation, and we cannot predict the ultimate cost of compliance with these requirements or their effect on our operations. Any suspensions, terminations or inability to meet applicable bonding requirements could materially adversely affect our financial condition and operations. Although significant expenditures may be required to comply with governmental laws and regulations applicable to us, compliance has not had a material adverse effect on our earnings or competitive position. Future regulations may add to the cost of, or significantly limit, drilling activity. See "—Risk Factors—We Are Subject To Various Governmental Regulations And Environmental Risks" and "Item 1. Business—Governmental Regulation" and "Item 1. Business—Environmental Matters".

Forward Looking Information

We or our representatives may make forward looking statements, oral or written, including statements in this report, press releases and filings with the SEC, regarding estimated future net revenues from oil and natural gas reserves and the present value thereof, planned capital expenditures (including the amount and nature thereof), increases in oil and gas production, the number of wells we anticipate drilling during 2003 and our financial position, business strategy and other plans and objectives for future operations. Although we believe that the expectations reflected in these forward looking statements are reasonable, there can be no assurance that the actual results or developments anticipated by us will be realized or, even if substantially realized, that they will have the expected effects on our business or operations. Among the factors that could cause actual results to differ materially from our expectations are general economic conditions, inherent uncertainties in interpreting engineering data, operating hazards, delays or cancellations of drilling operations for a variety of reasons, competition, fluctuations in oil and gas prices, availability of sufficient capital resources to us or our project participants, government regulations and other factors set forth among the risk factors noted below or in the description of our business in Item 1 of this report. All subsequent oral and written forward looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. We assume no obligation to update any of these statements.

Risk Factors

We Are Substantially Leveraged

Our outstanding long-term debt was $81.8 million as of December 31, 2002, and $78.1 million as of March 21, 2003. The credit agreements related to our new senior credit facility and senior subordinated notes facility limit the amount of additional debt borrowings, including borrowings under these facilities or other senior or subordinated indebtedness. As of March 21, 2003, we had $14 million of additional borrowing capacity under our new senior credit facility and no additional borrowing availability under our senior subordinated notes facility.

Our level of indebtedness will have several important effects on our operations, including those listed below.

- We will dedicate a substantial portion of our cash flow from operations to the payment of interest on our indebtedness and to the payment of our other current obligations, and will not have these cash flows available for other purposes.
- The covenants in our credit facilities limit our ability to borrow additional funds or dispose of assets and may affect our flexibility in planning for, and reacting to, changes in business conditions.
- Our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate purposes or other purposes may be impaired.

We may also be required to alter our capitalization significantly to accommodate future exploration, development or acquisition activities. These changes in capitalization may significantly alter our leverage and dilute the equity interests of existing stockholders. Our ability to meet our debt service obligations and to reduce our total indebtedness will be dependent upon our future performance, which will be subject to general economic conditions and to financial, business and other factors affecting our operations, many of which are beyond our control. We cannot assure you that our future performance will not be harmed by such economic conditions and financial, business and other factors. See "—Liquidity and Capital Resources".

We Have Substantial Capital Requirements

We make and will continue to make substantial capital expenditures in our exploration and development projects. While we believe that our cash flow from operations, remaining availability under our new senior credit facility and 2003 beginning cash balance should allow us to finance our planned operations through 2003 based on current conditions and expectations, additional financing could be required in the future to fund our exploration and development activities. We cannot assure you that we will be able to secure additional financing on reasonable terms or at all, or that financing will continue to be available to us under our existing or new financing arrangements. Without additional capital resources, our drilling and other activities may be limited and our business, financial condition and results of operations may suffer. See "—Liquidity and Capital Resources".

Volatility Of Oil And Gas Markets Affects Us; Oil And Natural Gas Prices Are Volatile

Our revenues, operating results and future rate of growth depend highly upon the prices we receive for our oil and natural gas production. Historically, the markets for oil and natural gas have been volatile and are likely to continue to be volatile in the future. Market prices of oil and natural gas depend on many factors beyond our control, including:

- worldwide and domestic supplies of oil and natural gas;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- political instability or armed conflict in oil-producing regions;
- the price and level of foreign imports;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the availability of pipeline capacity;
- weather conditions;
- domestic and foreign governmental regulations and taxes; and
- the overall economic environment.

We cannot predict future oil and natural gas price movements with certainty. During 2002, the high and low settlement prices for oil on the NYMEX were $32.72 per Bbl and $17.97 per Bbl, and the high and low settlement prices for natural gas on the NYMEX were $5.34 per MMBtu and $1.91 per MMBtu. Significant declines in oil and natural gas prices for an extended period may have the following effects on our business:

- limit our financial condition, liquidity, ability to finance planned capital expenditures and results of operations;
- reduce the amount of oil and natural gas that we can produce economically;
- cause us to delay or postpone some of our capital projects;
- reduce our revenues, operating income and cash flow; and
- reduce the carrying value of our oil and natural gas properties.

Our Hedging Transactions May Not Prevent Losses

In an attempt to reduce our sensitivity to energy price volatility, we use swap and collar hedging arrangements that generally result in a fixed price or a range of minimum and maximum price limits over a specified monthly time period. If we do not produce our oil and natural gas reserves at rates equivalent to our hedged position, we would be required to satisfy our obligations under hedging contracts on potentially unfavorable terms without the ability to hedge that risk through sales of comparable quantities of our own production. This situation occurred during portions of 2000, due in part to our sale of certain producing reserves in mid-1999. As a result, our cash flow was significantly reduced in 2000. Because the terms of our hedging contracts are based on assumptions and estimates of numerous factors such as cost of production and pipeline and other transportation and marketing costs to delivery points, substantial differences between the hedged prices and actual results could harm our anticipated profit margins and our ability to manage the risk associated with fluctuations in oil and natural gas prices. Hedging contracts limit the benefits we will realize if actual prices rise above the contract prices. We could be financially harmed if the other party to the hedging contracts proves unable or unwilling to perform its obligations under such contracts. See "—Other Matters—Derivative Instruments" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk".

Exploratory Drilling Is A Speculative Activity Involving Numerous Risks And Uncertain Costs; We Are Dependent On Exploratory Drilling Activities

Our revenues, operating results and future rate of growth depend highly upon the success of our exploratory drilling program. Exploratory drilling involves numerous risks, including the risk that we will not encounter commercially productive natural gas or oil reservoirs. We cannot always predict the cost of drilling, and we may be forced to limit, delay or cancel drilling operations as a result of a variety of factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment.

We may not be successful in our future drilling activities because even with the use of 3-D seismic and other advanced technologies, exploratory drilling is a speculative activity. We could incur losses because our use of 3-D seismic data and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies. Even when fully utilized and properly interpreted, our 3-D seismic data and other advanced technologies only assist us in identifying subsurface structures and do not indicate whether hydrocarbons are in fact present in those structures. Because we interpret the areas desirable for drilling from 3-D seismic data gathered over large areas, we may not acquire option and lease rights until after the seismic data is available and, in some cases, until the drilling locations are also identified. Although we have identified numerous potential drilling locations, we cannot assure you that we will ever lease, drill or produce oil or natural gas oil from these or any other potential drilling locations. We cannot assure you that we will be successful in our drilling activities, that our overall drilling success rate for activity within a particular province will not decline, or that our completed wells will ultimately produce our estimated economically recoverable reserves. Unsuccessful drilling activities could materially harm our operations and financial condition.

We Are Subject To Various Casualty Risks

Our operations are subject to hazards and risks inherent in drilling for and producing and transporting oil and natural gas, such as:

- fires;
- natural disasters;
- formations with abnormal pressures;
- blowouts, cratering and explosions; and
- pipeline ruptures and spills.

Any of these hazards and risks can result in the loss of hydrocarbons, environmental pollution, personal injury claims and other damage to our properties and the property of others. See "Item 1. Business—Operating Hazards and Uninsured Risks".

We May Not Have Enough Insurance To Cover Some Operating Risks

We maintain insurance coverage against some, but not all, potential losses in order to protect against operating hazards. We may elect to self-insure if our management believes that the cost of insurance, although available, is excessive relative to the risks presented. We generally maintain insurance for the hazards and risks inherent in drilling for and producing and transporting oil and natural gas and believe this insurance is adequate. If an event occurs that is not covered, or not fully covered, by insurance, it could harm our financial condition and results of operations. In addition, we cannot fully insure against pollution and environmental risks. See "Item 1. Business—Operating Hazards and Uninsured Risks".

The Marketability Of Our Production Is Dependent On Facilities That We Typically Do Not Own Or Control

The marketability of our production depends in part upon the availability, proximity and capacity of natural gas gathering systems, pipelines and processing facilities. We generally deliver natural gas through gas gathering systems and gas pipelines that we do not own. Our ability to produce and market oil and natural gas could be harmed by any dramatic change in market factors or by:

- federal and state regulation of oil and natural gas production and transportation;
- tax and energy policies;
- changes in supply and demand; and
- general economic conditions.

We Have Historical Operating Losses And Our Future Results May Vary

We cannot assure you that we will be profitable in the future. At December 31, 2002, we had an accumulated deficit of $24.4 million and total stockholders' equity of $61.7 million. We have recognized the following annual net losses before extraordinary items since 1995: $1.6 million in 1995, $450,000 in 1996, $1.1 million (including a net $1.2 million non-cash deferred income tax charge incurred in connection with our conversion from a partnership to a corporation) in 1997, $33.3 million (including a $25.9 million non-cash writedown in the carrying value of our oil and natural gas properties) in 1998, $21.6 million (including a $12.2 million non-cash loss on the sale of oil and natural gas properties) in 1999, and $15.7 million in 2000. See "Item 6. Selected Financial Data".

Our Future Operating Results May Fluctuate

Our future operating results may fluctuate significantly depending upon a number of factors, including:

- industry conditions;
- prices of oil and natural gas;
- rates of drilling success;
- capital availability;
- rates of production from completed wells; and
- the timing and amount of capital expenditures.

This variability could cause our business, financial condition and results of operations to suffer. In addition, any failure or delay in the realization of expected cash flows from operating activities could limit our ability to invest and participate in economically attractive projects.

Maintaining Reserves And Revenues In The Future Depends On Successful Exploration And Development

In general, production from oil and natural gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Except to the extent we conduct successful exploration and development activities or acquire properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. Our future oil and natural gas production depends highly upon our ability to economically find, develop or acquire reserves in commercial quantities.

The business of exploring for or developing reserves is capital intensive. Reductions in our cash flow from operations and limitations on or unavailability of external sources of capital may impair our ability to make the necessary capital investment to maintain or expand our asset base of oil and natural gas reserves. In addition, we cannot be certain that our future exploration and development activities will result in additional proved reserves or that we will be able to drill productive wells at acceptable costs. Furthermore, although significant increases in prevailing prices for oil and natural gas could cause increases in our revenues, our finding and development costs could also increase. Finally, we participate in a percentage of our wells as a non-operator. The failure of an operator of our wells to adequately perform operations, or an operator's breach of the applicable agreements, could harm us.

We Are Subject To Uncertainties In Reserve Estimates And Future Net Cash Flows

There is substantial uncertainty in estimating quantities of proved reserves and projecting future production rates and the timing of development expenditures. No one can measure underground accumulations of oil and natural gas in an exact way. Accordingly, oil and natural gas reserve engineering requires subjective estimations of those accumulations. Estimates of other engineers might differ widely from those of our independent petroleum engineers. Accuracy of reserve estimates depends on the quality of available data and on engineering and geological interpretation and judgment. Our independent petroleum engineers may make material changes to reserve estimates based on the results of actual drilling, testing, and production. As a result, our reserve estimates often differ from the quantities of oil and natural gas we ultimately recover. Also, we make certain assumptions regarding future oil and natural gas prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from these assumptions could greatly affect our estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery, and estimates of the future net cash flows. See "Item 2. Properties—Oil and Natural Gas Reserves".

Actual future net cash flows from our oil and natural gas properties also will be affected by factors such as:

- the amount and timing of actual production;
- supply and demand for oil and natural gas;
- limits or increases in consumption by gas purchasers; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows in compliance with the SEC reporting requirements may not necessarily be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

We Face Significant Competition

We operate in the highly competitive areas of oil and natural gas exploration, exploitation, acquisition and production with other companies. We face intense competition from a large number of independent, technology-driven companies as well as both major and other independent oil and natural gas companies in a number of areas such as:

- seeking to acquire desirable producing properties or new leases for future exploration;
- marketing our oil and natural gas production; and
- seeking to acquire the equipment and expertise necessary to operate and develop those properties.

Many of our competitors have financial and other resources substantially in excess of those available to us. This highly competitive environment could harm our business. See "Item 1. Business—Competition".

We Are Subject To Various Governmental Regulations And Environmental Risks

Our business is subject to federal, state and local laws and regulations relating to the exploration for, and the development, production and marketing of, oil and natural gas, as well as safety matters. Although we believe we are in substantial compliance with all applicable laws and regulations, legal requirements are frequently changed and subject to interpretation, and we are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. We may be required to make significant expenditures to comply with governmental laws and regulations.

Our operations are subject to complex environmental laws and regulations adopted by federal, state and local governmental authorities. Environmental laws and regulations change frequently, and the implementation of new, or the modification of existing, laws or regulations could harm us. The discharge of natural gas, oil, or other pollutants into the air, soil or water may give rise to significant liabilities on our part to the government and third parties and may require us to incur substantial costs of remediation. We cannot be certain that existing environmental laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations will not harm our results of operations and financial condition. See "Item 1. Business—Governmental Regulation" and "Item 1. Business—Environmental Matters".

Our Business May Suffer If We Lose Key Personnel

We have assembled a team of geologists and geophysicists who have considerable experience in applying 3-D imaging technology to explore for and to develop oil and natural gas. We depend upon the knowledge, skills and experience of these experts to provide 3-D imaging and to assist us in reducing the risks associated with our participation in oil and natural gas exploration and development projects. In addition, the success of our business depends, to a significant extent, upon the abilities and continued efforts of our management, particularly Ben M. Brigham, our Chief Executive Officer, President and Chairman of the Board. We have an employment agreement with Ben M. Brigham, but do not have an employment agreement with any of our other employees. We have key man life insurance on Mr. Brigham in the amount of $2 million. If we lose the services of our key management personnel or technical experts, or are unable to attract additional qualified personnel, our business, financial condition, results of operations, development efforts and ability to grow could suffer. We cannot assure you that we will be successful in attracting and retaining such executives, geophysicists, geologists and engineers. See "Item 1. Business—Exploration and Development Staff" and "Executive Officers of the Registrant".

Control By Certain Stockholders And Certain Anti-Takeover Provisions May Affect You; Certain Of Our Affiliates Control A Majority Of The Outstanding Common Stock

As of March 21, 2003, our directors, executive officers and 10% or greater stockholders, and certain of their affiliates, beneficially owned approximately 54% of our outstanding common stock. Accordingly, these stockholders, as a group, will be able to control the outcome of stockholder votes, including votes concerning the election of directors, the adoption or amendment of provisions in our certificate of incorporation or bylaws, and the approval of mergers and other significant corporate transactions. The existence of these levels of ownership concentrated in a few persons makes it unlikely that any other holder of common stock will be able to affect our management or direction. These factors may also have the effect of delaying or preventing a change in our management or voting control.

Certain Anti-Takeover Provisions May Affect Your Rights As A Stockholder

Our certificate of incorporation authorizes our Board of Directors to issue up to 10 million shares of preferred stock without stockholder approval and to set the rights, preferences and other designations, including voting rights, of those shares as the Board of Directors may determine. These provisions, alone or in combination with the other matters described in the preceding paragraph may discourage transactions involving actual or potential changes in our control, including transactions that otherwise could involve payment of a premium over prevailing market prices to holders of our common stock. We are also subject to provisions of the Delaware General Corporation Law that may make some business combinations more difficult.

The Market Price Of Our Stock Is Volatile

The trading price of our common stock and the price at which we may sell securities in the future is subject to large fluctuations in response to any of the following: limited trading volume in our stock, changes in government regulations, quarterly variations in operating results, our involvement in litigation, general market conditions, the prices of oil and natural gas, announcements by us and our competitors, our liquidity, our ability to raise additional funds and other events.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Management Opinion Concerning Derivative Instruments

We limit our use of derivative instruments principally to commodity price hedging activities, whereby gains and losses are generally offset by price changes in the underlying commodity. Our use of derivative instruments for hedging activities could materially affect its results of operations in particular quarterly or annual periods since such instruments can limit our ability to benefit from favorable oil and natural gas price movements.

Commodity Price Risk

Our primary commodity market risk exposure is to changes in the prices related to the sale of its oil and natural gas production. The market prices for oil and natural gas have been volatile and are likely to continue to be volatile in the future. As such, we employ established policies and procedures to manage our exposure to fluctuations in the sales prices we receives for its oil and natural gas production using derivative instruments.

We believe the use of derivative instruments, although not free of risk, allows us to reduce our exposure to oil and natural gas sales price fluctuations and thereby achieve a more predictable cash flow. While the use of derivative instruments limits the downside risk of adverse price movements, their use may also limit future revenues from favorable price movements. Moreover, our hedging arrangements generally do not apply to all of its production and thus provide only partial price protection against declines in commodity prices. We expect that the amount of our hedges will vary from time to time.

The gas derivative transactions are generally settled based upon the average of the reporting settlement prices on the NYMEX for the last three trading days of a particular contract month. The oil derivative transactions are generally settled based on the average reporting settlement prices on the NYMEX for each trading day of a particular calendar month.

The table below summarizes our total natural gas production volumes subject to derivative transactions during 2002 and the weighted average NYMEX reference price for those volumes.

Natural gas swaps		**Natural gas caps**	
Volumes (MMbtu)	3,358,500	Volumes (MMbtu)	1,810,000
Average price ($/MMbtu)	$ 3.132	Average price ($/MMbtu)	$ 2.633

The table below summarizes our total crude oil production volumes subject to derivative transactions during 2002 and the weighted average NYMEX reference price for those volumes.

Crude oil swaps		**Crude oil collars**	
Volumes (Bbls)	126,500	Volumes (Bbls)	204,500
Average price ($/Bbls)	$ 25.96	Average price ($/Bbls)	
		Floor	$ 18.00
		Ceiling	$ 22.36

As of March 21, 2003, our oil and gas derivative instruments were comprised of swaps, collars and floors.

For swap instruments, we receive a fixed price for the hedged commodity and pay a floating market price, as defined in each instrument, to the counterparty. These instruments are settled monthly. When the floating price exceeds the fixed price for a contract month, we pay the counterparty. When the fixed price exceeds the floating price, the counterparty is required to make a payment to us. We have designated theses swap instruments as cash flow hedges designed to achieve a more predictable cash flow, as well as reduce our exposure to price volatility.

For collar instruments, we establish a floor and ceiling price on future commodity production. These instruments are settled monthly. When the settlement price for a period is above the ceiling price the, we pay the counterparty. When the settlement price for a period is below the floor price, the counterparty is required to pay us. We have designated these collar instruments as cash flow hedges designed to achieve a more predictable cash flow, as well as reduce our exposure to price volatility.

For floor instruments, we establish a floor price on future commodity production. When the settlement price for a period is below the floor price, the counterparty is required to pay us.

The following tables reflect our natural gas derivative instruments, associated volumes and the corresponding weighted average NYMEX reference price by quarter.

	2003				2004			
As of March 21, 2003	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Natural gas swaps:								
Volumes (MMbtu)	832,500	819,000	598,000	414,000	295,750	227,500	138,000	92,000
Average price ($/MMBtu)	$ 3.632	$ 3.846	$ 3.867	$ 4.039	$ 4.963	$ 4.252	$ 4.180	$4.360
Natural gas floors:								
Volumes (MMbtu)	—	150,000	460,000	460,000	—	—	—	—
Average price ($/MMBtu)	$ —	$ 4.500	$ 4.500	$ 4.500	$ —	$ —	$ —	$ —

The following tables reflect our crude oil derivative instruments, associated volumes and the corresponding weighted average NYMEX reference price by quarter.

	2003				2004			
As of March 21, 2003	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Crude oil swaps:								
Volumes (Bbls)	67,500	61,425	55,200	41,400	29,575	20,475	13,800	9,200
Average price ($/Bbl)	$ 25.29	$ 25.22	$ 23.77	$ 23.21	$ 25.35	$ 24.52	$ 23.91	$23.80
Crude oil collars:								
Volumes (Bbls)	22,500	22,750	—	—	—	—	—	—
Average price ($/Bbl)								
Floor	$ 18.00	$ 18.00	$ —	$ —	$ —	$ —	$ —	$ —
Ceiling	22.56	22.56	—	—	—	—	—	—

Interest Rate Risk

We are subject to interest rate risk as borrowings under our senior credit facility ($60.0 million outstanding as of December 31, 2002) accrue interest at floating rates based on the lender's base rate or LIBOR. We do not utilize derivative instruments to protect against changes in interest rates on debt borrowings. Based on our outstanding borrowing under our senior credit facility at December 31, 2002, an adverse change (defined as a hypothetical 1% and 2% increase in interest rates on such borrowings) would reduce cash flow by approximately $600,000 and $1.2 million, respectively, from currently projected levels.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Our Consolidated Financial Statements required by this item are included on the pages immediately following the Index to Financial Statements appearing on page F-1.

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

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required by this item is incorporated by reference to information under the caption "Proposal One—Election of Directors" and to the information under the caption "Section 16(a) Beneficial Ownership Reporting Compliance" in our definitive 2003 Proxy Statement for our annual meeting of stockholders to be held on Wednesday, May 28, 2003. The 2003 Proxy Statement will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2002.

Pursuant to Item 401(b) of Regulation S-K, the information required by this item with respect to Brigham's executive officers is set forth in Part I of this report.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item is incorporated herein by reference to the 2003 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2002.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by this item is incorporated herein by reference to the 2003 Proxy Statement, which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2002. See "Item 5. Market for Registrants Common Equity and Related Stockholder Matters", which sets forth certain information with respect to our equity compensation plans.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

The information required by this item is incorporated herein by reference to the 2003 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2002.

ITEM 14. CONTROLS AND PROCEDURES

(a) *Evaluation of disclosure controls and procedures.* Within 90 days prior to the filing date of this Form 10-K, our principal executive officer (CEO) and principal financial officer (CFO) carried out an evaluation of the effectiveness of our disclosure controls and procedures. Based on this evaluation, the CEO and CFO believe that our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports it files under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and that such information is accumulated and communicated to our management, including the CEO and CFO, as appropriate to allow timely decisions regarding required disclosure; and that Brigham's disclosure controls and procedures are effective.

(b) *Changes in internal controls.* There have been no significant changes in our internal controls or in other factors that could significantly affect our internal controls subsequent to the evaluation referred to in Item 14. (a), above, nor have there been any corrective actions with regard to significant deficiencies or material weaknesses.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) 1. Consolidated Financial Statements:
See Index to Financial Statements on page F-1.

2. No schedules are required

3. Exhibits:

The exhibits listed in the accompanying Index to Exhibits are filed or incorporated by reference as part of the annual report.

(b) The following reports on Form 8-K were filed by Brigham during the last quarter of the period covered by this Annual Report on Form 10-K:

(1) Filed November 8, 2002 on Item 5. Other Events (Regarding third quarter 2002 operational and financial results)

(2) Filed December 27, 2002 on Item 5. Other Events (Regarding adoption of Rule 10b 5-1 (c) plans by certain officers)

GLOSSARY OF OIL AND GAS TERMS

The following are abbreviations and definitions of certain terms commonly used in the oil and gas industry and in this report.

All Sources Finding Costs. Net capitalized costs incurred in the acquisition, exploration and development of proved oil and natural gas reserves divided by total proved reserve additions. Total reserve additions includes extensions, discoveries, revisions of previous estimates and purchases of properties but excludes sales of properties.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to oil or other liquid hydrocarbons.

Bcf. One billion cubic feet.

Bcfe. One billion cubic feet of natural gas equivalent. In reference to natural gas, natural gas equivalents are determined using the ratio of 6 Mcf of natural gas to 1 Bbl of oil, condensate of natural gas liquids.

CAEX. Computer-aided exploration.

Completion. The installation of permanent equipment for the production of oil or natural gas.

Completion Rate. The number of wells on which production casing has been run for a completion attempt as a percentage of the number of wells drilled.

Developed Acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development Well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Drilling Finding Costs. The costs associated with drilling and completing a well divided by total proved reserve additions. The costs do not include seismic and land acquisition costs for that well, future development costs associated with proved undeveloped reserves added by the well, capitalized general and administrative cost or capitalized interest.

Dry Well. A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion of an oil or gas well.

Exploratory Well. A well drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir.

Finding and Development Costs. Capital costs incurred in the acquisition, exploration and development of proved oil and natural gas reserves divided by total proved reserve additions.

Gross Acres or Gross Wells. The total acres or wells, as the case may be, in which Brigham has a working interest.

MBbl. One thousand barrels of oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet of natural gas.

Mcfe. One thousand cubic feet of natural gas equivalents.

MMBbl. One million barrels of oil or other liquid hydrocarbons.

MMBtu. One million Btu, or British Thermal Units. One British Thermal Unit is the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

MMcf. One million cubic feet of natural gas.

MMcfe. One million cubic feet of natural gas equivalents.

Net Acres or Net Wells. Gross acres or wells multiplied, in each case, by the percentage working interest owned by Brigham.

Net Production. Production that is owned by Brigham less royalties and production due others.

Oil. Crude oil, condensate or other liquid hydrocarbons.

Operator. The individual or company responsible for the exploration, development, and production of an oil or gas well or lease.

Present Value of Future Net Revenues or PV10%. The pretax present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%.

Proved Developed Finding Costs. The costs associated with drilling and completing a well divided by total proved developed reserve additions. The costs do not include seismic and land acquisition costs for that well, future development costs associated with proved undeveloped reserves added by the well, capitalized general and administrative cost or capitalized interest.

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 for recompletion.

Psi. Pounds per square inch.

Royalty. An interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

Spud. Start drilling a new well (or restart).

Standardized Measure. The aftertax present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%.

2-D Seismic. The method by which a cross-section of the earth's subsurface is created through the interpretation of reflecting seismic data collected along a single source profile.

3-D Seismic. The method by which a three dimensional image of the earth's subsurface is created through the interpretation of reflection seismic data collected over surface grid. 3-D seismic surveys allow for a more detailed understanding of the subsurface than do conventional surveys and contribute significantly to field appraisal, development and production.

Working Interest. An interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, hereunder duly authorized, as of March 31, 2003.

BRIGHAM EXPLORATION COMPANY

By: /s/ BEN M. BRIGHAM

Ben M. Brigham
Chief Executive Officer, President and Chairman of the Board

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below as of March 31, 2003, by the following persons on behalf of the Registrant and in the capacity indicated.

/s/ BEN M. BRIGHAM

Ben M. Brigham
Chief Executive Officer, President and Chairman of the Board
(Principal Executive Officer)

/s/ EUGENE B. SHEPHERD, JR.

Eugene B. Shepherd, Jr.
Chief Financial Officer
(Principal Financial and Accounting Officer)

/s/ ANNE L. BRIGHAM

Anne L. Brigham
Director

/s/ HAROLD D. CARTER

Harold D. Carter
Director

/s/ STEPHEN C. HURLEY

Stephen C. Hurley
Director

/s/ STEPHEN P. REYNOLDS

Stephen P. Reynolds
Director

/s/ HOBART. A. SMITH

Hobart A. Smith
Director

/s/ STEVEN A. WEBSTER

Steven A. Webster
Director

/s/ R GRAHAM WHALING

R. Graham Whaling
Director

CERTIFICATIONS

I, Bud M. Brigham, Chief Executive Officer of Brigham Exploration Company (the "Registrant"), certify that:

1. I have reviewed this annual report on Form 10-K of Brigham Exploration Company;
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15-d-14) for the registrant and we have:
   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and
   c) presented in this annual report our conclusions and about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):
   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and
6. The registrant's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 31, 2003

/s/ BEN M. BRIGHAM

Bud M. Brigham
Chief Executive Officer, President and
Chairman of the Board

CERTIFICATIONS

I, Eugene B. Shepherd, Jr., Chief Financial Officer of Brigham Exploration Company, (the "Registrant"), certify that:

1. I have reviewed this annual report on Form 10-K of Brigham Exploration Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15-d-14) for the registrant and we have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions and about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 31, 2003

/s/ EUGENE B. SHEPHERD, JR.

Eugene B. Shepherd, Jr.
Chief Financial Officer

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BRIGHAM EXPLORATION COMPANY

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors
and Stockholders of Brigham Exploration Company

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of stockholders' equity and of cash flows present fairly, in all material respects, the financial position of Brigham Exploration Company (the "Company") and its subsidiaries at December 31, 2002 and 2001, and the results of their operations and their cash flows for the three years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the consolidated financial statements, the Company changed its method of accounting for derivative instruments and hedging activities effective January 1, 2001.

As discussed in Note 10 to the consolidated financial statements, the Company has restated diluted earnings per share data for 2001.

PricewaterhouseCoopers LLP

March 27, 2003
Dallas, Texas

BRIGHAM EXPLORATION COMPANY
CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

	December 31, 2002	December 31, 2001
ASSETS		
Current assets:		
Cash and cash equivalents	$ 15,318	$ 5,112
Accounts receivable	11,361	9,113
Other current assets	6,643	2,410
Total current assets	33,322	16,635
Oil and natural gas properties, using the full cost method of accounting		
Unproved	37,403	35,908
Proved	229,991	203,803
Accumulated depletion	(102,414)	(87,820)
	164,980	151,891
Other property and equipment, net	1,234	1,331
Deferred loan fees	2,391	3,166
Other noncurrent assets	132	52
	$ 202,059	$173,075
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 14,486	$ 8,146
Royalties payable	4,508	145
Accrued drilling costs	2,727	1,969
Participant advances received	1,955	158
Other current liabilities	10,334	4,515
Total current liabilities	34,010	14,933
Senior credit facility	60,000	75,000
Senior subordinated notes	21,797	16,721
Other noncurrent liabilities	186	206
Commitments and contingencies		
Series A Preferred Stock, mandatorily redeemable, $.01 par value, $20 stated and redemption value, 2,250,000 shares authorized, 1,765,132 and 1,630,692 shares issued and outstanding at December 31, 2002 and 2001, respectively	19,540	16,614
Series B Preferred Stock, mandatorily redeemable, $.01 par value, $20 stated and redemption value, 1,000,000 shares authorized, 501,226 shares issued and outstanding at December 31, 2002	4,777	—
Stockholders' equity:		
Preferred stock, $.01 par value, 10 million shares authorized, of which 2,250,000 and 1,000,000 shares are designated as Series A and Series B, respectively	—	—
Common stock, $.01 par value, 50 million shares authorized, 20,618,161 and 17,127,650 shares issued and 19,479,979 and 16,016,113 shares outstanding at December 31, 2002 and 2001, respectively	206	171
Additional paid-in capital	93,436	80,466
Treasury stock, at cost; 1,138,182 and 1,111,537 shares at December 31, 2002 and 2001, respectively	(4,282)	(4,165)
Unearned stock compensation	(212)	(494)
Accumulated other comprehensive (loss) income	(3,047)	351
Accumulated deficit	(24,352)	(26,728)
Total stockholders' equity	61,749	49,601
	$ 202,059	$173,075

The accompanying notes are an integral part of these consolidated financial statements.

BRIGHAM EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)

	Year Ended December 31, 2002	2001	2000
Revenues:			
Oil and natural gas sales	$35,100	$ 32,293	$19,143
Other revenue	76	255	69
	35,176	32,548	19,212
Costs and expenses:			
Lease operating	3,759	3,486	2,139
Production taxes	1,977	1,511	1,786
General and administrative	4,971	3,638	3,100
Depletion of oil and natural gas properties	14,594	13,211	7,920
Depreciation and amortization	440	677	620
	25,741	22,523	15,565
Operating income	9,435	10,025	3,647
Other income (expense):			
Interest income	119	264	108
Interest expense	(6,238)	(6,681)	(9,906)
Debt conversion expense	(630)	—	—
Other income (expense)	(310)	8,080	(9,504)
	(7,059)	1,663	(19,302)
Income (loss) before income taxes and extraordinary item	2,376	11,688	(15,655)
Income taxes	—	—	—
Income (loss) before extraordinary item	2,376	11,688	(15,655)
Extraordinary item—gain on refinancing of senior subordinated notes, net of $0 tax	—	—	32,267
Net income	2,376	11,688	16,612
Less accretion and dividends on redeemable preferred stock	2,952	2,450	275
Net income (loss) available to common stockholders	$ (576)	$ 9,238	$16,337
Net income (loss) per share available to common stockholders:			
Basic			
Income (loss) before extraordinary item	$ (0.04)	$ 0.58	$ (0.98)
Extraordinary item	—	—	1.99
	$ (0.04)	$ 0.58	$ 1.01
		Restated—Note 10	
Diluted			
Income (loss) before extraordinary item	$ (0.04)	$ 0.44	$ (0.98)
Extraordinary item	—	—	1.99
	$ (0.04)	$ 0.44	$ 1.01

The accompanying notes are an integral part of these consolidated financial statements.

BRIGHAM EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(in thousands)

	Common Stock Shares	Common Stock Amounts	Additional Paid In Capital	Treasury Stock	Unearned Stock Compensation	Accumulated Other Comprehensive Income	Accumulated Deficit	Total Stockholders' Equity
Balance, December 31, 1999	14,518	$145	$64,171	$ —	$ (290)	$ —	$(55,028)	$ 8,998
Net income	—	—	—	—	—	—	16,612	16,612
Exercise of employee stock options	8	—	19	—	—	—	—	19
Issuance of common stock	2,195	22	4,166	—	—	—	—	4,188
Issuance of restricted stock	309	3	1,137	—	(1,140)	—	—	—
Issuance of stock options	—	—	185	—	(185)	—	—	—
Forfeiture of stock options	—	—	(60)	—	10	—	—	(50)
Issuance of warrants	—	—	13,910	—	—	—	—	13,910
Cancellation of warrants	—	—	(4,979)	—	—	—	—	(4,979)
Amortization of unearned stock compensation	—	—	—	—	284	—	—	284
Purchase of treasury stock	—	—	—	(3,950)	—	—	—	(3,950)
In kind dividends on Series A mandatorily redeemable Preferred Stock	—	—	(267)	—	—	—	—	(267)
Accretion on Series A mandatorily redeemable Preferred Stock	—	—	(8)	—	—	—	—	(8)
Balance, December 31, 2000	17,030	170	78,274	(3,950)	(1,321)	—	(38,416)	34,757
Comprehensive income (loss):								
Net income	—	—	—	—	—	—	11,688	11,688
Cumulative effect (loss) on adoption of SFAS 133	—	—	—	—	—	(11,800)	—	(11,800)
Unrealized gain on cash flow hedges	—	—	—	—	—	12,151	—	12,151
Comprehensive income								12,039
Exercise of employee stock options	97	1	251	—	—	—	—	252
Forfeitures of employee stock options	—	—	(115)	—	31	—	—	(84)
Forfeitures of restricted stock	—	—	6	(148)	121	—	—	(21)
Purchases of restricted stock	—	—	—	(67)	—	—	—	(67)
Issuance of warrants	—	—	4,500	—	—	—	—	4,500
In kind dividends on Series A mandatorily redeemable Preferred Stock	—	—	(2,347)	—	—	—	—	(2,347)
Accretion on Series A mandatorily redeemable Preferred Stock	—	—	(103)	—	—	—	—	(103)
Amortization of unearned stock compensation	—	—	—	—	675	—	—	675
Balance, December 31, 2001	17,127	171	80,466	(4,165)	(494)	351	(26,728)	49,601

BRIGHAM EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (Continued)
(in thousands)

	Common Stock		Additional Paid In Capital	Treasury Stock	Unearned Stock Compensation	Accumulated Other Comprehensive Income	Accumulated Deficit	Total Stockholders' Equity
	Shares	Amounts						
Balance, December 31, 2001	17,127	171	80,466	(4,165)	(494)	351	(26,728)	49,601
Comprehensive income (loss):								
Net income	—	—	—	—	—	—	2,376	2,376
Unrealized loss on cash flow hedges	—	—	—	—	—	(3,519)	—	(3,519)
Net losses included in net income	—	—	—	—	—	121	—	121
Comprehensive income (loss)								(1,022)
Exercise of employee stock options	133	1	295	—	—	—	—	296
Expiration of employee stock options	—	—	(46)	—	—	—	—	(46)
Forfeitures of restricted stock	—	—	(1)	(41)	15	—	—	(27)
Revision of terms of employee stock options	—	—	596	—	—	—	—	596
Repurchases of common stock	—	—	—	(76)	—	—	—	(76)
Issuance of warrants	—	—	4,605	—	—	—	—	4,605
Warrants exercised for common stock	244	2	623	—	—	—	—	625
Common stock issued in exchange for warrants and convertible debt rights	550	6	(56)	—	—	—	—	(50)
Debt converted to common stock	2,564	26	9,906	—	—	—	—	9,932
In kind dividends on Series A mandatorily redeemable preferred stock	—	—	(2,689)	—	—	—	—	(2,689)
Accretion on Series A mandatorily redeemable preferred stock	—	—	(238)	—	—	—	—	(238)
In kind dividends on Series B mandatorily redeemable preferred stock	—	—	(24)	—	—	—	—	(24)
Accretion on Series B mandatorily redeemable preferred stock	—	—	(1)	—	—	—	—	(1)
Amortization of unearned stock compensation	—	—	—	—	267	—	—	267
Balance, December 31, 2002	20,618	$206	$93,436	$(4,282)	$(212)	$(3,047)	$(24,352)	$61,749

The accompanying notes are an integral part of these consolidated financial statements.

BRIGHAM EXPLORATION COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2002	2001	2000
Cash flows from operating activities:			
Net income	$ 2,376	$ 11,688	$ 16,612
Adjustments to reconcile net income to cash provided (used) by operating activities:			
Depletion of oil and natural gas properties	14,594	13,211	7,920
Depreciation and amortization	440	677	620
Interest paid through issuance of additional senior subordinated notes	1,076	721	4,575
Amortization of deferred loan fees	1,191	1,372	1,283
Amortization of discount on senior subordinated notes	—	—	673
Amortization of deferred loss on derivative instruments	—	—	280
Market value adjustment for derivative instruments	(263)	(9,666)	8,885
Extraordinary gain on refinancing of senior subordinated notes	—	—	(32,267)
Loss on investment in Brigham Duke LLC	—	94	—
Stock option compensation expense	596	—	—
Changes in working capital and other items:			
Accounts receivable	(2,248)	(48)	(4,332)
Other current assets	(4,534)	(1,550)	(262)
Accounts and royalties payable	10,703	(920)	(7,290)
Other current liabilities	5,060	3,188	(1,354)
Noncurrent assets	2	13	54
Noncurrent liabilities	(20)	(70)	(32)
Net cash provided (used) by operating activities	28,973	18,922	(4,635)
Cash flows from investing activities:			
Additions to oil and natural gas properties	(27,696)	(34,532)	(28,910)
Proceeds from sale of oil and natural gas properties	871	397	3,938
Additions to other property and equipment	(249)	(396)	(162)
(Increase) decrease in drilling advances paid	(132)	960	(937)
Net cash used by investing activities	(27,206)	(33,571)	(26,071)
Cash flows from financing activities:			
Proceeds from issuance of common stock	—	—	4,188
Proceeds from issuance of preferred stock and warrants	9,356	9,838	20,060
Proceeds from issuance of senior subordinated notes and warrants	4,000	9,000	7,000
Proceeds from exercise of employee stock options	296	252	19
Proceeds from exercise of warrants	625	—	—
Fees paid due to common stock exchange for warrants	(50)	—	—
Repurchases of common stock	(76)	(67)	—
Increase in senior credit facility	—	—	19,000
Repayment of senior credit facility	(5,000)	—	—
Principal payments on senior subordinated notes	—	—	(20,354)
Principal payments on capital lease obligations	(28)	(99)	(210)
Deferred loan fees paid	(684)	—	(902)
Net cash provided by financing activities	8,439	18,924	28,801
Net increase (decrease) in cash and cash equivalents	10,206	4,275	(1,905)
Cash and cash equivalents, beginning of year	5,112	837	2,742
Cash and cash equivalents, end of year	$ 15,318	$ 5,112	$ 837

The accompanying notes are an integral part of these consolidated financial statements.

1. Organization and Nature of Operations

Brigham Exploration Company is a Delaware corporation formed on February 25, 1997 for the purpose of exchanging its common stock for the common stock of Brigham, Inc. and the partnership interests of Brigham Oil & Gas, L.P. (the "Partnership"). Hereinafter, Brigham Exploration Company and the Partnership are collectively referred to as "Brigham." Brigham, Inc. is a Nevada corporation whose only asset is its ownership interest in the Partnership. The Partnership was formed in May 1992 to explore and develop onshore domestic oil and natural gas properties using 3-D seismic imaging and other advanced technologies. Since its inception, the Partnership has focused its exploration and development of oil and natural gas properties primarily in West Texas, the Anadarko Basin and the onshore Gulf Coast.

2. Summary of Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of 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 the reporting period. The most significant estimates relate to proved oil and natural gas reserve volumes and the future development costs as well as estimates relating to certain oil and natural gas revenues and expenses. Actual results may differ from those estimates.

Principles of Consolidation

The accompanying financial statements include the accounts of Brigham and its wholly owned subsidiaries, and its proportionate share of assets, liabilities and income and expenses of the limited partnerships in which Brigham, or any of its subsidiaries has a participating interest. All significant intercompany accounts and transactions have been eliminated.

Cash and Cash Equivalents

Brigham considers all highly liquid financial instruments with an original maturity of three months or less to be cash equivalents.

Property and Equipment

Brigham uses the full cost method of accounting for oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including payroll, other internal costs, and interest incurred for the purpose of finding oil and natural gas reserves, are capitalized. Internal costs capitalized are directly attributable to acquisition, exploration and development activities and do not include costs related to production, general corporate overhead or similar activities. Costs associated with production and general corporate activities are expensed in the period incurred.

Proceeds from the sale of oil and natural gas properties are applied to reduce the capitalized costs of oil and natural gas properties unless the sale would significantly alter the relationship between capitalized costs and proved reserves, in which case a gain or loss is recognized.

Capitalized costs associated with impaired properties and capitalized costs related to properties having proved reserves, plus the estimated costs of future development, dismantlement, restoration and abandonment costs, net of estimated salvage values, are amortized using the unit-of-production method

2. Summary of Significant Accounting Policies (Continued)

based on proved reserves. Capitalized costs of oil and natural gas properties, net of accumulated amortization, are limited to the total of estimated future net cash flows from proved oil and natural gas reserves, discounted at ten percent, plus the cost of unevaluated properties. There are many factors, including global events that may influence the production, processing, marketing and valuation of oil and natural gas. A reduction in the valuation of oil and natural gas properties resulting from declining prices or production could adversely impact depletion rates and capitalized cost limitations.

Capitalized costs associated with properties that have not been evaluated through drilling or seismic analysis are excluded from the unit-of-production amortization. Exclusions are adjusted annually based on drilling results and interpretative analysis.

Other property and equipment, which primarily consists of 3-D seismic interpretation workstations, is depreciated on a straight-line basis over the estimated useful lives of the assets after considering salvage value. Estimated useful lives are as follows:

Furniture and fixtures	10 years
Machinery and equipment	5 years
3-D seismic interpretation workstations and software	3 years

Betterments and major improvements that extend the useful lives are capitalized while expenditures for repairs and maintenance of a minor nature are expensed as incurred.

Revenue Recognition

Brigham recognizes crude oil revenues using the sales method of accounting. Under this method, Brigham recognizes revenues when oil is delivered and title transfers.

Brigham recognizes natural gas revenues using the entitlements method of accounting. Under this method, revenues are recognized based on Brigham's entitled ownership percentage of sales of natural gas to purchasers. Gas imbalances occur when Brigham sells more or less than its entitled ownership percentage of total natural gas production. When Brigham receives less than its entitled share, a receivable is recorded. When Brigham receives more than its entitled share, a liability is recorded. At December 31, 2002, Brigham had recorded a receivable of approximately 1,180 MMcf and $3.7 million and a liability of approximately 1,486 MMcf and $5.7 million associated with gas imbalances. At December 31, 2001, Brigham had recorded a receivable of approximately 441 MMcf and $1.5 million and a liability of approximately 758 MMcf and $2.7 million associated with gas imbalances.

Derivative Instruments and Hedging Activities

Brigham uses derivative instruments to manage market risks resulting from fluctuations in commodity prices of natural gas and crude oil. Brigham periodically enters into commodity contracts, including price swaps, caps and floors, which require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a fixed quantity of natural gas or crude oil without the exchange of underlying volumes. The notional amounts of these financial instruments are based on expected production from existing wells.

Prior to January 1, 2001, in order for a derivative instrument to qualify for hedge accounting, there must have been clear correlation between the derivative instrument and the forecasted transaction. Correlation of the commodity contracts was determined by evaluating whether the contract gains and

2. Summary of Significant Accounting Policies (Continued)

losses would substantially offset the effects of price changes on the underlying natural gas and crude oil sales volumes. To the extent that correlation existed between the contracts and the underlying natural gas and crude oil sales volumes, realized gains or losses and related cash flows arising from the contracts were recognized as a component of oil and natural gas sales in the same period as the sale of the underlying volumes. To the extent that correlation did not exist between the contracts and the underlying natural gas and crude oil sales volumes, realized gains or losses and related cash flows arising from the contracts were recognized in the period incurred as a component of other income or loss. The fair market value of any contract that did not meet the correlation test outlined above was recorded as a deferred gain or loss on the balance sheet and was adjusted to current market value at each balance sheet date with any deferred gains or losses recognized as a component of other income.

On January 1, 2001, Brigham adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"), as amended. Effective with the adoption of SFAS 133, all derivatives are recorded on the balance sheet at fair value and changes in the fair value of derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and, if it is, depending on the type of hedge transaction. Brigham's derivatives consist primarily of cash flow hedge transactions in which Brigham is hedging the variability of cash flows related to a forecasted transaction. Changes in the fair value of these derivative instruments designated as cash flow hedges will be reported in other comprehensive income and will be reclassified as earnings in the periods in which earnings are impacted by the variability of the cash flows of the hedged item. The ineffective portion of the cash flow hedges will be recognized in current period earnings. Gains and losses on derivative instruments that do not qualify for hedge accounting are included in other income (expense) in the period in which they occur. The resulting cash flows from derivatives are reported as cash flows from operating activities.

The adoption of SFAS 133 resulted in a January 1, 2001 transition adjustment to record a net of tax cumulative effect of $11.8 million to other comprehensive income to recognize the fair value (liability) of all derivative instruments that qualified for hedge accounting treatment. Gains and losses on derivatives that were previously deferred as adjustments to the carrying amount of hedged items were not adjusted.

At the inception of a derivative contract, Brigham may designate the derivative as a cash flow hedge. For all derivatives designated as cash flow hedges, Brigham formally documents the relationship between the derivative contract and the hedged items, as well as the risk management objective for entering into the derivative contract. To be designated as a cash flow hedge transaction, the relationship between the derivative and the hedged items must be highly effective in achieving the offset of changes in cash flows attributable to the risk both at the inception of the derivative and on an ongoing basis. Brigham measures hedge effectiveness on a quarterly basis and hedge accounting is discontinued prospectively if it is determined that the derivative is no longer effective in offsetting changes in the cash flows of the hedged item. Gains and losses deferred in accumulated other comprehensive income related to cash flow hedge derivatives that become ineffective remain unchanged until the related production is delivered. If Brigham determines that it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the hedging instrument are recognized in earnings immediately. See Note 12 for a description of the derivative contracts in which Brigham participates.

2. Summary of Significant Accounting Policies (Continued)

Other Comprehensive Income

Brigham follows the provisions of Statement of Financial Accounting Standards No. 130, "Reporting Comprehensive Income," which establishes standards for reporting comprehensive income. In addition to net income, comprehensive income includes all changes in equity during a period, except those resulting from investments and distributions to stockholders of Brigham. Brigham had no such changes prior to 2001. The components of other comprehensive income for the years ended December 31 follow (in thousands):

	2002	2001	2000
Balance, beginning of year	$ 351	$ —	$ —
Cumulative effect of adoption of SFAS No. 133	—	(11,800)	—
Current period settlements reclassified to earnings	1,847	(9,646)	—
Current period change in fair value of hedges	(5,366)	21,797	—
Net losses included in earnings	121	—	—
Balance, end of year	$ (3,047)	$ 351	$ —

Stock Based Compensation

Brigham accounts for employee stock-based compensation using the intrinsic value method prescribed by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees". Accordingly, Brigham has adopted the disclosure-only provisions of Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" ("SFAS 123").

The weighted average fair value per share of stock compensation issued during 2002, 2001 and 2000 was $3.44, $2.19, and $1.92, respectively. The fair value for these options was estimated using the Black-Scholes model with the following weighted average assumptions for grants made in 2002, 2001 and 2000; risk free interest rate of 4.1%, 4.9% and 6.2%; volatility of the expected market prices of Brigham's common stock of 102%, 60% and 67%; expected dividend yield of zero and weighted average expected option lives of 7.0, 7.0 and 6.6 years, respectively.

The Black-Scholes valuation model was developed for use in estimating the fair value of traded options that have no vesting restrictions and are transferable. Additionally, the assumptions required by the valuation model are highly subjective. Because Brigham's stock options have significantly different characteristics from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, in management's opinion the model does not necessarily provide a reliable single measure of the fair value of Brigham's stock options.

Had compensation cost for Brigham's stock options been determined based on the fair market value at the grant dates of the awards consistent with the methodology prescribed by SFAS 123 as

2. Summary of Significant Accounting Policies (Continued)

amended by SFAS 148, Brigham's net income (loss) and net income (loss) per share for the years ended December 31, 2002, 2001 and 2000 would have been the pro forma amounts indicated below:

	2002	2001	2000
Net income available to common stockholders (in thousands):			
As reported	$ (576)	$9,238	$16,337
Add back: Stock compensation expense previously included in net income	101	295	124
Effect of total employee stock-based compensation expense, determined under fair value method for all awards	(513)	(347)	1,009
Pro forma	$ (988)	$9,186	$17,470
Net income per share:			
Basic:			
As reported	$(0.04)	$ 0.58	$ 1.01
Pro forma	(0.06)	0.57	1.08
Diluted:			
As reported	$(0.04)	$ 0.44	$ 1.01
Pro forma	(0.06)	0.44	1.08

2. Summary of Significant Accounting Policies (Continued)

Income Taxes

Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to the differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using the tax rate in effect for the year in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates of deferred tax assets and liabilities is recognized in income in the year of the enacted rate change. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Deferred Loan Fees

Deferred loan fees are incurred in connection with the issuance of debt and are recorded on the balance sheet as deferred assets. The debt issue costs are amortized to interest expense over the life of the debt using the straight-line method. The results obtained using the straight-line method are not materially different than those that would result from using the effective interest method.

Segment Information

All of Brigham's oil and natural gas properties and related operations are located in the United States and management has determined that Brigham has one reportable segment.

Treasury Stock

Treasury stock purchases are recorded at cost. Upon reissuance, the cost of treasury shares held is reduced by the average purchase price per share of the aggregate treasury shares held.

New Pronouncements

In June 2001, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations". SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in 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, a gain or loss is recognized. Brigham will adopt this standard as required on January 1, 2003. Brigham is currently evaluating the effect of this statement on its consolidated financial position, results of operations and cash flows.

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB statements No. 4, 44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections" ("SFAS 145"). SFAS 145 requires, except in the case of events or transactions of a highly unusual and infrequent nature, gains or losses from the early extinguishment of debt to be classified as components of a company's income or loss from continuing operations. Prior to the adoption of the provisions of SFAS 145, gains or losses on the early extinguishment of debt were required to be classified in a company's periodic consolidated statements of operations as extraordinary gains or losses, net of associated income taxes, after the determination of income or loss from continuing operations. SFAS No. 145 is effective for fiscal years

2. Summary of Significant Accounting Policies (Continued)

beginning after May 15, 2002. Due to the requirements of SFAS No. 145, it is less likely that a gain or loss on extinguishment of debt would be classified as an extraordinary item in Brigham's results of operations.

Reclassifications

Certain reclassifications have been made to the prior year balances to conform to current year presentation.

3. Asset Dispositions

In February 1999, Brigham entered into a project financing arrangement with Duke Energy Financial Services, Inc. ("Duke") to fund the continued exploration of five projects covered by approximately 200 square miles of 3-D seismic data acquired in 1998. In this transaction, Brigham conveyed 100% of its working interest in land and seismic in these project areas to a newly formed limited liability company (the "Brigham-Duke LLC") for a total consideration of $10 million. Brigham was the managing member of the Brigham-Duke LLC with a 1% interest and Duke was the sole remaining member with a 99% interest. Pursuant to the terms of the Brigham-Duke LLC agreement, Brigham paid 100% of the drilling and completion costs for all wells drilled by the Brigham-Duke LLC in exchange for a 70% working interest in the wells and their associated drilling and spacing units and allocable seismic data. Upon 100% project payout, Brigham had certain rights to back-in for up to a 94% effective working interest in the Brigham-Duke LLC properties. In February 2001, Duke, as majority member of the Brigham-Duke LLC elected to dissolve the Brigham-Duke LLC. As a result of the dissolution of the Brigham-Duke LLC, the remaining undeveloped land and seismic data in the Brigham-Duke LLC project areas were unconditionally owned by Duke and, in December 2001, Brigham recorded a loss of approximately $94,000 on its investment in the Brigham-Duke LLC.

4. Property and Equipment

Property and equipment, at cost, are summarized as follows (in thousands):

	December 31, 2002	December 31, 2001
Oil and natural gas properties	$ 267,394	$239,711
Accumulated depletion	(102,414)	(87,820)
	164,980	151,891
Other property and equipment:		
3-D seismic interpretation workstations and software	2,445	2,307
Office furniture and equipment	2,337	2,225
Accumulated depreciation	(3,548)	(3,201)
	1,234	1,331
	$ 166,214	$153,222

Brigham capitalizes certain payroll and other internal costs directly attributable to acquisition, exploration and development activities as part of its investment in oil and natural gas properties over

4. Property and Equipment (Continued)

the periods benefited by these activities. During the years ended December 31, 2002, 2001 and 2000, these capitalized costs amounted to $4.2 million, $3.9 million and $3.4 million, respectively. Capitalized costs do not include any costs related to production, general corporate overhead, or similar activities. Interest costs of $0.9 million, $1.8 million and $2.8 million were capitalized in 2002, 2001 and 2000, respectively.

5. Senior Credit Facility and Senior Subordinated Notes

	December 31,	
	2002	2001
Senior Credit Facility	$60,000	$75,000
Senior Subordinated Notes	21,797	16,721
Total Debt	$81,797	$91,721
Less: Current Maturities	—	—
Total Long-Term Debt	$81,797	$91,721

Senior Credit Facility

As of December 31, 2002, Brigham had $60.0 million in borrowings outstanding under its senior credit facility. Principal outstanding under the senior credit facility is due at maturity with interest due monthly for base rate tranches or periodically as London Interbank Offered Rate (LIBOR) tranches mature. The annual interest rate for borrowings under the senior credit facility is either the lender's base rate or London Interbank Offered Rate (LIBOR) (1.5% on December 31, 2002) plus 3.00%, at Brigham's option. Obligations under the senior credit facility are secured by substantially all of Brigham's oil and natural gas properties and other tangible assets.

The senior credit facility contains various restrictive covenants and compliance requirements, which include minimum current ratio, interest coverage ratio, limitations on capital expenditures related to seismic and land activities, and various other financial covenants. At December 31, 2002 and for the year then ended, Brigham was in compliance with all covenant requirements.

In December 2002, the senior credit facility was amended to extend the maturity date to December 31, 2004 and to provide Brigham with $65 million in funding commitments under a revolving credit structure. In December 2001, the senior credit facility was amended to extend the maturity date to December 31, 2003. Brigham recognized $323,000 and $200,000 during 2002 and 2001, respectively, as additional deferred loan fees relating to these amendments. The additional deferred loan fees and the unamortized deferred loan fees will be amortized over the remaining life of the senior credit facility.

The senior credit facility was amended in February 2000, to provide Brigham with $75 million in borrowing availability. As part of the amendment, $30 million of the senior credit facility held by Shell Capital was designated as convertible notes. To facilitate this conversion Brigham issued to Shell Capital warrants to be converted into shares of Brigham common stock in the following amounts and prices: (i) $10 million is convertible at $3.90 per share, (ii) $10 million is convertible at $6.00 per share and (iii) $10 million is convertible at $8.00 per share.

5. Senior Credit Facility and Senior Subordinated Notes (Continued)

In addition, certain financial covenants of the senior credit facility were amended or added in the July 1999, February 2000 and October 2000 amendments. In connection with the February 2000 amendment, Brigham reset the price of the warrants previously issued to its existing senior lenders to purchase one million shares of Brigham common stock from the then current exercise price of $2.25 per share to $2.02 per share.

In December 2002, Brigham entered into a series of transactions whereby a number of warrants and convertible debt rights were extinguished or converted. Brigham issued 550,000 unregistered shares of its common stock to Shell Capital in exchange for Shell Capital's warrant position (see Senior Subordinated Notes below), and to terminate Shell Capital's right to convert $30 million of Brigham's senior credit facility into shares of Brigham common stock. Also, DLJ Merchant Banking Partners III, L.P. in conjunction with GlobalEnergy Partners, both affiliates of CSFB Private Equity, purchased $10 million of Brigham's senior credit facility from Shell Capital and converted it into 2,564,102 shares of Brigham's common stock at an exercise price of $3.90 per share. Brigham recorded $0.6 million in debt conversion expenses associated with this conversion.

The following table details the warrant position and convertible debt rights that were extinguished or converted as a result of the these transactions:

	Exercise Price	# Shares
$10 million of Convertible Notes	$3.90	2,564,102
$10 million of Convertible Notes	$6.00	1,666,667
$10 million of Convertible Notes	$8.00	1,250,000
Warrants issued with Senior Subordinated Notes Facility	$3.00	1,250,000
		6,730,769

As further discussed in Note 6, Brigham issued 500,000 shares of Series B preferred stock and 2.3 million warrants to purchase Brigham's common stock for net proceeds of $9.4 million. In addition, Brigham used $5.0 million of the net proceeds from the Series B preferred offering to repay outstanding indebtedness under its senior credit facility.

In March 2003, Brigham replaced its senior credit facility with a new senior credit facility that provides for a maximum $80 million in commitments, an initial borrowing base of $70 million and matures in March 2006. As of the closing date of the facility, Brigham had $56 million in outstanding borrowings under the new senior credit facility. Borrowings under the new senior credit facility are secured by substantially all of Brigham's oil and natural gas properties and other tangible assets and bear interest at either the base rate of Société Générale or LIBOR, at Brigham's option, plus a margin that varies according to facility usage. Interest is paid quarterly. The collateral value and borrowing base are redetermined periodically. The unused portion of the committed borrowing base is subject to an annual commitment fee of 0.50%.

The new senior credit facility agreement contains various covenants and restrictive provisions, which limit Brigham's ability to incur additional indebtedness, sell properties, purchase or redeem capital stock, make investments or loans, create liens and make certain acquisitions. The new senior credit facility requires Brigham to maintain a current ratio (as defined) of at least 1 to 1 and an interest coverage ratio (as defined) of at least 3.25 to 1.

5. Senior Credit Facility and Senior Subordinated Notes (Continued)

Senior Subordinated Notes

As of December 31, 2002, Brigham had $21.8 million of senior subordinated notes outstanding. The senior subordinated notes bear interest at 10.75% per annum, payable quarterly in arrears on the last day of January, April, July and October, are redeemable at Brigham's option for face value at any time and have no principal repayment obligations until maturity in October 2005. At Brigham's option, up to 50% of the interest payments on the senior subordinated notes can be satisfied by payment in kind through the issuance of additional senior subordinated notes in lieu of cash. In December 2002, Brigham extended its option to satisfy 50% of its interest obligation in this manner through October 2003. For the years ended December 31, 2002 and 2001, Brigham exercised this option and issued an additional $1.1 and $0.7 million, respectively, of senior subordinated notes.

The senior subordinated notes are issued pursuant to the senior subordinated notes facility dated October 31, 2000. Under the senior subordinated notes facility, Shell Capital agreed to provide up to $20 million (plus any amount of interest paid in kind) in senior subordinated notes in borrowing increments of at least $1 million. Once borrowings under the senior subordinated notes facility have been repaid they cannot be withdrawn. The senior subordinated notes are secured obligations ranking junior to Brigham's senior credit facility and have covenants similar to the senior credit facility. In connection with the senior subordinated credit agreement in October 2000, Brigham issued warrants to purchase 1,250,000 shares of Brigham common stock at an exercise price of $3.00 per share. The warrants had a term of seven years and a cashless exercise feature. Brigham valued the warrants using the Black-Scholes Option Pricing Model and recorded the estimated value of $2.9 million as deferred loan costs which are being amortized over the five-year term of the senior subordinated notes. The warrants were extinguished in December 2002 (see Senior Credit Facility above).

At January 1, 2000, Brigham had a subordinated notes agreement with $41.3 million total outstanding and warrants issued to the notes holders to purchase one million shares of common stock at an exercise price of $3.50 per share. In February 2000, in connection with an amendment to the agreement, the exercise price on the warrants was reduced to $2.43 per share. Brigham issued an additional $4.6 million in subordinated notes as payment in kind of interest for the year ended December 31, 2000. In November 2000, these subordinated notes and warrants were purchased by Brigham for $20 million resulting in an extraordinary gain of $32.3 million, net of transaction costs of $1.7 million.

6. Preferred Stock

In October 2000, Brigham designated 1.5 million shares of preferred stock as Series A Preferred Stock, and in November 2000, issued 1.0 million shares of mandatorily redeemable preferred stock (the "Series A Preferred Stock") and warrants to purchase 6,666,667 shares of Brigham's common stock (the "Series A Warrants") for net proceeds of $19.8 million. The proceeds from the issuance of the Series A Preferred Stock and Series A Warrants were used to purchase the subordinated notes and warrants held by the holder of the subordinated notes as described in Note 5.

The Series A Preferred Stock has a par value of $.01 per share and a stated value of $20 per share. The Series A Preferred Stock is cumulative and pays dividends quarterly at a rate of 6% per annum of the stated value if paid in cash or 8% per annum of the stated value if paid in kind ("PIK") through the issuance of additional Series A Preferred Stock in lieu of cash. At Brigham's option, up to 100% of the dividend payments on the Series A Preferred Stock can be paid by the issuance of PIK

6. Preferred Stock (Continued)

dividends for five years. The Series A Preferred Stock matures in ten years and is redeemable at Brigham's option at 100% or 101% of stated value (depending upon certain conditions) at anytime prior to maturity.

The Series A Warrants have a term of ten years, an exercise price of $3.00 per share and must be exercised, if Brigham so requires, in the event Brigham's common stock trades above $5.00 per share for 60 consecutive trading days. The exercise price of the Series A Warrants is payable either in cash or in shares of the Series A Preferred Stock valued at liquidation value plus accrued dividends. If Brigham requires exercise of the Series A Warrants, proceeds will be used to fund the redemption of a similar value of then outstanding Series A Preferred Stock. The Series A Warrants were valued at $11.5 million using the Black-Scholes Option Pricing model and were recorded as additional paid-in capital in 2000. This discount accretes to the Series A Preferred Stock dividends during the life of the securities using the effective interest method.

In March 2001, Brigham designated an additional 750,000 shares of preferred stock as Series A and issued 500,000 shares of Series A Preferred Stock and 2,105,263 warrants to purchase Brigham's common stock (the "Additional Series A Warrants") for net proceeds of $9.8 million.

The Additional Series A Warrants have terms similar to the Series A Warrants described above except the Additional Series A Warrants have an exercise price of $4.75 per share and must be exercised, if Brigham so requires, in the event that Brigham's common stock trades at an average above 150% of the exercise price (currently $6.525 per share) for 60 consecutive trading days. The Additional Series A Warrants were valued at approximately $4.5 million using the Black-Scholes Option Pricing model and were recorded as additional paid-in capital in March 2001. This discount accretes to the Series A Preferred Stock dividends during the life of the securities using the effective interest method. In connection with the issuance of Series B Preferred Stock in December 2002, the exercise price of the Additional Series A warrants was reset from the then current exercise price of $4.75 per share to $4.35 per share.

Brigham had 1,765,132 and 1,630,692 shares of Series A Preferred Stock issued and outstanding with a redemption value of $35.3 million and $32.6 million at December 31, 2002 and 2001, respectively. For the year ended December 31, 2002 and 2001, Brigham issued an additional 134,430 and 130,692 shares, respectively, of Series A Preferred Stock as PIK dividends.

In December 2002, Brigham designated 1,000,000 shares of preferred stock as Series B and issued 500,000 shares of Series B Preferred Stock and warrants to purchase 2,298,851 shares of Brigham's common stock (the "Series B Warrants") for net proceeds of $9.4 million. A portion of the proceeds were used to reduce borrowings under the Senior Credit Facility by $5 million. The Series B Preferred Stock is cumulative and pays dividends quarterly at a rate of 6% per annum of the stated value if paid in cash or 8% per annum of the stated value if PIK through the issuance of additional Series B Preferred Stock in lieu of cash. At Brigham's option, up to 100% of the dividend payments on the Series B Preferred Stock can be paid by the issuance of PIK dividends for five years. The Series B Preferred Stock matures in ten years and is redeemable in whole at Brigham's option at 101% of the stated value five years after closing.

The Series B Preferred Stock ranks in parity with the Series A Preferred Stock and senior as to dividend, redemption and liquidation rights to all other classes and series of capital stock of Brigham authorized on the date of issuance, or to any other class or series of capital stock issued while any

6. Preferred Stock (Continued)

shares of the Series B Preferred Stock remain outstanding. The Series B Preferred Stock does not generally have any voting rights, except for certain approval rights and as required by law.

The Series B Warrants have terms similar to the Series A Warrants described above with an exercise price of $4.35 per share and must be exercised, if Brigham so requires, in the event that Brigham's common stock trades at an average of at least 150% of the exercise price ($6.525 per share) for 60 consecutive trading days. The Series B Warrants were valued at approximately $4.6 million using the Black-Scholes Option Pricing model and were recorded as additional paid-in capital in December 2002. This discount accretes to the Series B Preferred Stock dividends during the life of the securities using the effective interest method.

Brigham had 501,226 shares of Series B Preferred Stock issued and outstanding with a redemption value of $10.0 million at December 31, 2002. For the year ended December 31, 2002, Brigham issued an additional 1,226 shares of Series B Preferred Stock as PIK dividends.

7. Issuance of Common Stock

In December 2002, Brigham issued 550,000 shares of Brigham common stock to Shell Capital in exchange for Shell Capital's warrants and associated convertible debt rights. In addition, Brigham issued 2,564,102 shares of Brigham common stock upon the conversion of $10 million of the senior credit facility. See further discussion above in Note 5.

In February 2000, Brigham issued 2,195,122 shares of common stock and 731,707 warrants to purchase Brigham's common stock for total net proceeds of approximately $4.2 million in a private placement to a group of institutional investors led by affiliates of two members of Brigham's board of directors. The equity sale consisted of units that included one share of common stock and one-third of a warrant to purchase Brigham's common stock at an exercise price of $2.5625 per share. In December 2002, 243,902 of these warrants were exercised for common stock resulting in net proceeds of approximately $625,000. In February 2003, the remaining 487,805 warrants were exercised under a cashless feature resulting in the issuance of 248,028 shares of Brigham common stock.

8. Capital Lease Obligations

Property under capital leases consists of the following (in thousands):

	December 31, 2002	December 31, 2001
3-D seismic interpretation workstations and software	$ —	$ 45
Office furniture and equipment	—	167
	—	212
Accumulated depreciation and amortization	—	(175)
	$ —	$ 37

There are no obligations under capital leases as of December 31, 2002.

9. Income Taxes

The provision for income taxes consists of the following (in thousands):

	Year Ended December 31,		
	2002	2001	2000
Current income taxes:			
Federal	$ —	$ —	$ —
State	—	—	—
Deferred income taxes:			
Federal	—	—	—
State	—	—	—
	$ —	$ —	$ —

The differences in income taxes provided and the amounts determined by applying the federal statutory tax rate to income before income taxes result from the following (in thousands):

	Year Ended December 31,		
	2002	2001	2000
Tax at statutory rate	$ 832	$ 4,091	$ 5,814
Add the effect of:			
Nondeductible expenses	223	4	12
Deductible stock compensation	(110)	(9)	—
Valuation allowance	(945)	(4,086)	(5,826)
	$ —	$ —	$ —

9. Income Taxes (Continued)

The components of deferred income tax assets and liabilities are as follows (in thousands):

	December 31, 2002	December 31, 2001
Deferred tax assets:		
Net operating loss carryforwards	$ 34,814	$ 31,085
Capital loss carryforwards	1,001	438
Stock compensation	808	745
Gas imbalances	698	445
Unrealized hedging losses	1,066	—
Other	32	7
	38,419	32,720
Deferred tax liability:		
Depreciable and depletable property	(29,544)	(24,058)
Derivative liabilities	(325)	(233)
	(29,869)	(24,291)
Net deferred tax asset	8,550	8,429
Valuation allowance	(8,550)	(8,429)
	$ —	$ —

Realization of deferred tax assets associated with net operating loss carryforwards ("NOLs") and other credit carryforwards is dependent upon generating sufficient taxable income prior to their expiration. At December 31, 2002, management believes it is more likely than not that these NOLs and other credit carryforwards may expire unused and, accordingly, has established a valuation allowance of $8.6 million against them. The valuation allowance was increased by $0.1 million in 2002 due to an increase of $5.6 million in deferred tax liabilities, partially offset by a $5.7 million increase in carryforward and other amounts. Deferred tax assets of $1.1 million related to unrealized hedging losses in other comprehensive income are included in this $5.7 million increase.

At December 31, 2002, Brigham has regular tax NOLs of approximately $99.5 million. Additionally, Brigham has approximately $84.9 million of alternative minimum tax ("AMT") NOLs available as a deduction against future AMT income. The NOLs expire from 2012 through 2022. The

9. Income Taxes (Continued)

value of these NOLs depends on the ability of Brigham to generate taxable income. A summary of our NOLs follows:

	Regular NOLs	AMT NOLs
Expiration Date:		
December 31, 2012	$13,327	$ 8,703
December 31, 2018	26,411	23,170
December 31, 2019	20,806	20,196
December 31, 2020	12,512	7,587
December 31, 2021	19,116	18,440
December 31, 2022	7,298	6,799
	$99,470	$84,895

In addition, at December 31, 2002, Brigham has capital loss carryforwards of approximately $2.9 million that expire in varying years through 2007.

Brigham believes it has a $5 million limitation on its NOLs under Internal Revenue Code Section 382 due to a potential 50% change in ownership among its 5% shareholders over a three-year period.

10. Net Income (Loss) Per Share

Basic earnings per share are computed by dividing net income (loss) available to common stockholders by the weighted average number of common shares outstanding for the period. The computation of diluted net income (loss) per share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock or resulted in the issuance of common stock that would then share in the earnings of Brigham.

	Year Ended December 31,		
	2002	2001 Restated	2000
Basic EPS:			
Income (loss) available to common stockholders before extraordinary item	$ (576)	$ 9,238	$(15,930)
Extraordinary item	—	—	32,267
Income (loss) available to common stockholders	$ (576)	$ 9,238	$ 16,337
Common shares outstanding	16,138	15,988	16,241
Basic EPS			
Income (loss) available to common stockholders before extraordinary item	$ (0.04)	$ 0.58	$ (0.98)
Extraordinary item	—	—	1.99
	$ (0.04)	$ 0.58	$ 1.01

10. Net Income (Loss) Per Share (Continued)

	Year Ended December 31, 2002	2001 Restated	2000
Diluted EPS:			
Income (loss) available to common stockholders before extraordinary item	$ (576)	$ 9,238	$(15,930)
Extraordinary item	—	—	32,267
Income (loss) available to common stockholders	$ (576)	$ 9,238	$ 16,337
Adjustments for assumed conversions:			
Interest on convertible debt	—	826	—
Dividends and accretion on mandatorily redeemable preferred stock	—	2,364	—
	—	3,190	—
Income (loss) available to common stockholders before extraordinary item—diluted	$ (576)	$12,428	$(15,930)
Extraordinary item	—	—	32,267
Income (loss) available to common stockholders—diluted	$ (576)	$12,428	$ 16,337
Common shares outstanding	16,138	15,988	16,241
Effect of dilutive securities:			
Convertible debt	—	2,564	—
Warrants	—	926	—
Mandatorily redeemable preferred stock	—	8,426	—
Stock options	—	301	—
Potentially dilutive common shares	—	12,217	—
Adjusted common shares outstanding—diluted	16,138	28,205	16,241
Diluted EPS (as restated for 2001—see below)			
Income (loss) available to common stockholders before extraordinary item	$ (0.04)	$ 0.44	$ (0.98)
Extraordinary item	—	—	1.99
	$ (0.04)	$ 0.44	$ 1.01

At December 31, 2002, 2001, and 2000, potential dilution of approximately 14.3 million, 3.0 million and 11.1 million shares of common stock, respectively, related to mandatorily redeemable preferred stock, convertible debt, warrants and options were outstanding, but were not included in the computation of diluted income (loss) per share because the effect of these instruments would have been anti-dilutive.

Restatement—Diluted earnings per share for 2001 have been restated (downward) to appropriately reflect the impact of Brigham's convertible debt, mandatorily redeemable preferred stock and associated warrants. The revised calculations utilize the "if-converted" method, as the holders can

10. Net Income (Loss) Per Share (Continued)

exercise the warrants either by paying cash or tendering the related convertible debt or mandatorily redeemable preferred stock.

	Quarter		Year to Date	
	As Reported	Restated	As Reported	Restated
March 31, 2001	$ 0.02	$ 0.02	$0.02	$0.02
June 30, 2001	$ 0.46	$ 0.30	$0.51	$0.36
September 30, 2001	$ 0.17	$ 0.13	$0.67	$0.49
December 31, 2001	$(0.15)	$(0.15)	$0.54	$0.44

There is no impact on previously reported diluted earnings per share data for 2002 or 2000.

11. Contingencies, Commitments and Factors Which May Affect Future Operations

Litigation

Brigham is, from time to time, party to certain lawsuits and claims arising in the ordinary course of business. While the outcome of lawsuits and claims cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on the financial condition, results of operations or cash flows of Brigham.

On June 1, 2001, Leonel Garcia, a landowner in Brooks County, Texas, filed suit against Brigham claiming that Brigham transported natural gas under his property through an existing pipeline without his consent. Mr. Garcia claimed $1.2 million in actual damages and $3 million in exemplary damages. In May 2002, Brigham settled the case through mediation for a cash payment of $125,000. Subsequently, Brigham began using an alternate pipeline.

On November 20, 2001, Brigham filed a lawsuit in the District Court of Travis County, Texas against Steve Massey Company, Inc. ("Massey") for breach of contract. The Petition claims Massey furnished defective casing to Brigham, which ultimately led to the casing failure of the Palmer "347" No. 5 well (the "Palmer #5") and the loss of the Palmer #5 as a producing well. Brigham believes the amount of damages incurred due to the loss of the Palmer #5 may exceed $5 million. Massey joined as additional defendants to the lawsuit other parties that had responsibility for the manufacture, importation or fabrication of the casing for its use in the Palmer #5. The case is currently in discovery. A trial has been set for August 2003.

On February 20, 2002, Massey filed an Original Petition to Foreclose Lien in Brooks County, Texas. Massey's Petition claims Brigham breached its contract for failure to pay for the casing it furnished Brigham for the Palmer #5 (and that Brigham's claim is defective, forming the basis of the lawsuit described in the paragraph above). Massey's Petition claims Brigham owes Massey a total of $445,819. Brigham's Motion to Transfer Venue to Travis County, Texas, and Motion to Consolidate Massey's claim with Brigham's suit against Massey pending in Travis County, were recently granted. If Massey is successful in its claim, Massey would have the right to foreclose its lien against the well, associated equipment and Brigham's leasehold interest. At this point in time, Brigham cannot predict the outcome of either its Travis County case or Massey's claim.

On July 11, 2002, an employee of a contractor on Brigham's Burkhart #1-R location, Matagorda County, Texas, was involved in a fatal accident. The United States Department of Labor Occupational

11. Contingencies, Commitments and Factors Which May Affect Future Operations (Continued)

Safety & Health Administration investigated the accident and issued three citations and imposed a total of $168,000 in fines. Brigham is appealing the citations, but at this time, cannot predict the outcome of that appeal.

On October 8, 2002, relatives of the contractor's employee filed a wrongful death action in the district court for Matagorda County, Texas, against Brigham and three of Brigham's contractors in connection with his accidental death on July 11, 2002. Plaintiffs are seeking unspecified both actual and punitive damages. Brigham cannot predict the outcome of this case, however Brigham believes it has sufficient insurance to cover the claim.

As of December 31, 2002, there were no known environmental or other regulatory matters related to Brigham's operations that are reasonably expected to result in a material liability to Brigham. Compliance with environmental laws and regulations has not had, and is not expected to have, a material adverse effect on Brigham's capital expenditures, earnings or competitive position.

Operating Lease Commitments

Brigham leases office equipment and space under operating leases expiring at various dates. The noncancelable term of the lease for Brigham's office space expires in 2007 with an option to renew for an additional five years. The future minimum annual rental payments under the noncancelable terms of these leases at December 31, 2002 are as follows (in thousands):

2003	$ 885
2004	885
2005	885
2006	885
2007	443
	$3,983

Future minimum rental payments are not reduced by minimum sublease rental income of approximately $13,000 due in 2003 under noncancelable subleases.

Rental expense for the years ended December 31, 2002, 2001 and 2000 was approximately $868,000, $731,000 and $805,000, respectively.

Major Purchasers

The following purchasers accounted for 10% or more of Brigham's oil and natural gas sales for the years ended December 31, 2002, 2001 and 2000:

	2002	2001	2000
Purchaser A	19%	45%	36%
Purchaser B	—	15%	20%
Purchaser C	15%	—	—
Purchaser D	11%	—	—

11. Contingencies, Commitments and Factors Which May Affect Future Operations (Continued)

Brigham believes that the loss of any individual purchaser would not have a long-term material adverse impact on its financial position or results of operations.

Factors Which May Affect Future Operations

Since Brigham's major products are commodities, significant changes in the prices of oil and natural gas could have a significant impact on Brigham's results of operations for any particular year.

12. Derivative Instruments and Hedging Activities

Brigham utilizes various commodity swap and option contracts to (i) reduce the effects of volatility in price changes on the oil and natural gas commodities it produces and sells, (ii) support its capital budgeting plans, and (iii) lock-in prices to protect the economics related to certain capital projects.

Natural Gas Derivative Contracts

The following table sets forth Brigham's outstanding natural gas hedging contracts and the weighted average NYMEX prices for those contracts as of December 31, 2002:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Outstanding Average
2003—Swap Contracts					
Volume (MMbtu)	832,500	591,500	460,000	322,000	549,851
Price per MMBtu	$ 3.63	$ 3.32	$ 3.50	$ 3.73	$ 3.54

The following table sets forth the natural gas hedging contracts Brigham entered subsequent to December 31, 2002 and the weighted average NYMEX prices for those contracts:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Outstanding Average
2003—Swap Contracts					
Volume (MMbtu)	—	227,500	138,000	92,000	114,692
Price per MMBtu	$ —	$ 5.21	$ 5.08	$ 5.12	$ 5.15
2003—Floors					
Volume (MMbtu)	—	150,000	460,000	460,000	187,912
Price per MMBtu	$ —	$ 4.50	$ 4.50	$ 4.50	$ 4.50
2004—Swap Contracts					
Volume (MMbtu)	295,750	227,500	138,000	92,000	187,912
Price per MMBtu	$ 4.96	$ 4.25	$ 4.18	$ 4.36	$ 4.53

12. Derivative Instruments and Hedging Activities (Continued)

Oil Derivative Contracts

The following table sets forth Brigham's outstanding oil hedging contracts and the weighted average NYMEX prices for those contracts as of December 31, 2002:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Outstanding Average
2003—Swap Contracts					
Volume (Bbl)	67,500	50,050	55,200	41,400	53,471
Price per Bbl	$ 25.29	$ 24.28	$ 23.77	$ 23.21	$ 24.26
2003—Collars					
Volume (Bbl)	22,500	22,750	—	—	
Ceiling price per Bbl	$ 22.56	$ 22.56	$ —	$ —	
Floor price per Bbl	$ 18.00	$ 18.00	$ —	$ —	

The following table sets forth the oil hedging contracts Brigham entered subsequent to December 31, 2002 and the weighted average NYMEX prices for those contracts:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Outstanding Average
2003—Swap Contracts					
Volume (Bbl)	—	11,375	—	—	2,836
Price per Bbl	$ —	$ 29.33	$ —	$ —	$ 29.33
2004—Swap Contracts					
Volume (Bbl)	29,575	20,475	13,800	9,200	18,145
Price per Bbl	$ 25.35	$ 24.52	$ 23.91	$23.80	$ 24.65

At December 31, 2002, the fair value of hedging contracts included in accumulated other comprehensive income and other current liabilities was approximately $3.2 million which is expected to be included in the results of operations for the year ended December 31, 2003. At December 31, 2001, the fair value of hedging contracts included in accumulated other comprehensive income and other current assets was approximately $351,000 of which approximately $50,000 was classified as noncurrent assets.

Brigham reports average oil and natural gas prices and revenues including the net results of hedging activities. The following table sets forth Brigham's oil and natural gas prices including and

12. Derivative Instruments and Hedging Activities (Continued)

excluding the hedging gains and losses and the increase or decrease in oil and natural gas revenues as a result of the hedging activities for the three year period ended December 31, 2002:

	Year Ended December 31,		
	2002	2001	2000
Natural Gas			
Average price per Mcf as reported (including hedging results)	$ 3.21	$ 3.11	$ 1.94
Average price per Mcf realized (excluding hedging results)	$ 3.33	$ 4.29	$ 4.06
Decrease in revenue (in thousands)	$ 712	$8,001	$9,400
Oil			
Average price per Bbl as reported (including hedging results)	$23.55	$24.05	$29.17
Average price per Bbl realized (excluding hedging results)	$25.17	$24.38	$29.47
Decrease in revenue (in thousands)	$1,135	$ 153	$ 107

Derivative instruments that do not qualify as hedging contracts are recorded at fair value on the balance sheet. At each balance sheet date, the value of these derivatives is adjusted to reflect current fair value and any gains or losses are recognized as other income or expense. At December 31, 2002 and 2001, the fair value of these derivatives included in other liabilities was $0 and $0.4 million, respectively. Brigham recognized $0.4 million, $9.7 million and $(8.9) million in non-cash gains (losses) related to changes in the fair values of these derivative contracts and $0.6 million, $1.5 million, and $0.6 million in losses related to the cash settlement payments made by Brigham to the counterparty for the years ended December 31, 2002, 2001 and 2000, respectively.

For the year ended December 31, 2002, ineffectiveness associated with Brigham's derivative commodity instruments designated as cash flow hedges decreased earnings by approximately $0.1 million. These amounts are included in other income and expense. There was no ineffectiveness for the year ended December 31, 2001.

13. Financial Instruments

Brigham's non-derivative financial instruments include cash and cash equivalents, accounts receivable, accounts payable and long-term debt. The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximate fair value because of their immediate or short-term maturities. The carrying value of Brigham's Senior Credit Facility approximates its fair market value since it bears interest at floating market interest rates. The fair value of Brigham's Senior Subordinated Notes at December 31, 2002 and 2001 was $24.0 million and $13.9 million, respectively.

Brigham's accounts receivable relate to oil and natural gas sold to various industry companies, and amounts due from industry participants for expenditures made by Brigham on their behalf. Credit terms, typical of industry standards, are of a short-term nature and Brigham does not require collateral. Brigham's accounts receivable at December 31, 2002 and 2001 do not represent significant credit risks as they are dispersed across many counterparties. Counterparties to the natural gas and crude oil price swaps are investment grade financial institutions.

14. Employee Benefit Plans

Brigham has adopted a defined contribution 401(k) plan for substantially all of its employees. The plan provides for Brigham matching of employee contributions to the plan, at Brigham's discretion. During 2002 and 2001, Brigham matched 25% of eligible employee contributions. Based on attainment of performance goals established at the beginning of 2002, Brigham matched an additional 62.5% and 17% of eligible employee contributions made during 2002 and 2001, respectively. Brigham contributed $260,000 and $102,000 to the 401(k) plan for the years ended December 31, 2002 and 2001, respectively, to match eligible contributions by employees. Brigham did not match employee contributions in 2000.

15. Stock Based Compensation

Brigham provides an incentive plan for the issuance of stock options, stock appreciation rights, stock, restricted stock, cash or any combination of the foregoing. The objective of this plan is to reward key employees whose performance may have a significant effect on the success of Brigham. An aggregate of 1,588,170 shares of Brigham's common stock was reserved for issuance pursuant to this plan. By resolution of the stockholders in May 2001, the number of shares of common stock available under the plan was amended to equal the lesser of 13% of the shares of common stock of Brigham issued and outstanding at any time or 2,077,335 shares. The Compensation Committee of the Board of Directors determines the type of awards made to each participant and the terms, conditions and limitations applicable to each award. At December 31, 2002, Brigham has issued approximately 85,000 incentive awards in excess of the amount currently authorized by the plan. Brigham will ask stockholders to approve an increase in the total shares available for incentive awards at the next annual meeting in May 2003. The requested increase will be greater than 85,000 shares. Options granted subsequent to March 4, 1997 have an exercise price equal to the fair market value of Brigham's common stock on the date of grant and generally vest over three to five years.

In May 2002, Brigham accelerated the vesting of certain employee stock options and extended the time limitation for exercising certain employee stock options following termination of employment. These revisions resulted in the immediate recognition of stock compensation cost as measured at the effective date of the changes. Accordingly, a non-cash charge to general and administrative expense in the amount of $596,000 was recorded.

Brigham also maintains a plan under which it offers stock compensation to non-employee directors. Pursuant to the terms of the plan, non-employee directors are entitled to annual grants. Options granted under this plan have an exercise price equal to the fair market value of Brigham's common stock on the date of grant and generally vest over five years.

15. Stock Based Compensation (Continued)

The following table summarizes activity under the incentive plan for each of the three years ended December 31, 2002:

	Shares	Weighted Average Exercise Price
Options outstanding December 31, 1999	1,519,726	$ 4.47
Options granted	793,500	2.83
Options forfeited or cancelled	(898,112)	(5.57)
Options exercised	(8,000)	(5.11)
Options outstanding December 31, 2000	1,407,114	2.89
Options granted	546,500	3.44
Options forfeited or cancelled	(239,369)	(3.48)
Options exercised	(97,474)	(2.59)
Options outstanding December 31, 2001	1,616,771	3.00
Options granted	475,000	4.12
Options forfeited or cancelled	(177,129)	(3.25)
Options exercised	(132,507)	(2.23)
Options outstanding December 31, 2002	1,782,135	$ 3.34

Brigham is required to use variable accounting for 252,500 of the stock options granted during 2000 of which 217,000 remain outstanding at December 31, 2002. This method of accounting requires recognition of noncash compensation expense for the difference between the option exercise price and the market price of Brigham's stock at the end of the accounting period of vested options. Since the market price for Brigham's stock is a component of the variable cost accounting calculation, it is not possible to determine the total noncash compensation expense that will be recognized during the vesting period of these options.

The following table summarizes information about stock options outstanding at December 31, 2002:

	Options Outstanding			Options Exercisable	
Exercise Price	Number Outstanding at December 31, 2002	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable at December 31, 2002	Weighted-Average Exercise Price
$1.55 to $1.83	181,500	4.1 years	$1.83	105,000	$1.83
2.38 to 3.41	869,635	5.0 years	2.48	414,293	2.64
3.61 to 5.19	719,000	5.7 years	4.07	129,300	3.75
6.31 to 14.38	12,000	2.8 years	6.98	9,533	7.16
$1.55 to $14.38	1,782,135	5.2 years	$3.34	658,126	$2.79

15. Stock Based Compensation (Continued)

Exchange of Certain Options for Shares of Restricted Stock

On October 25, 2000, the compensation committee of the Board of Directors approved a proposal to give its employees a one-time right to elect to cancel all or half of their outstanding employee stock options which were previously granted with exercise prices of $5.00 per share (the "$5 Options") or $6.31 per share (the "$6.31 Options") and to receive in exchange shares of restricted stock under Brigham's 1997 Incentive Plan. The exchange ratios were .643 shares of restricted stock for each share of common stock underlying a $5 Option and .4 shares of restricted stock for each share of common stock underlying a $6.31 Option.

Pursuant to the option exchange offer, on October 27, 2000, a total of 244,794 of the $5 Options were canceled in exchange for 157,401 shares of restricted stock, and a total of 379,665 of the $6.31 Options were canceled in exchange for 151,866 shares of restricted stock. Regardless of whether the canceled options were vested or unvested, the shares of restricted stock vest 25% per year beginning October 27, 2000. The restricted stock agreements contain provisions for accelerated vesting in some circumstances, which provisions are similar to those in the agreements covering the canceled options. This exchange resulted in noncash compensation expense of approximately $1.1 million that is being recognized over the vesting period of the restricted stock.

16. Related Party Transactions

During the years ended December 31, 2002, 2001 and 2000, Brigham incurred costs of approximately $1.1 million, $0.4 million and $0.1 million, respectively, in fees for land acquisition services performed by a company owned by a brother of Brigham's President and Chief Executive Officer and its Executive Vice President—Land and Administration. Other participants in Brigham's 3-D seismic projects reimbursed Brigham for a portion of these amounts. At December 31, 2002 and 2001, Brigham had recorded a liability in accounts payable of approximately $0 and $30,000, respectively, related to services performed by this company.

A director of Brigham served as a consultant to Brigham on various aspects of its business and strategic issues. Fees paid for these services by Brigham were approximately $45,000, $44,000 and $33,000 for the years ended December 31, 2002, 2001 and 2000, respectively. Additional disbursements totaling approximately $12,000, $6,000 and $12,000 were made during 2002, 2001 and 2000, respectively, for the reimbursement of certain expenses. At December 31, 2002 and 2001, there were no payables related to these services recorded by Brigham.

At December 31, 2002 Brigham had short-term accounts receivable of approximately $94,000 from a director of Brigham. These receivables represent the director's share of costs related to his working interest ownership in the Staubach No. 1, Burkhart #1R and Matthes-Huebner #1 wells that are operated by Brigham. The director obtained his interest in these wells through an exploration and production company that is not affiliated with Brigham. At December 31, 2002, $23,000 of the balance due was current and the remainder was over ninety days past due. Open short-term accounts receivable with the director are approximately $15,000 as of March 2003 and are thirty days past due.

On March 1, 2002, Brigham ended an agreement to sell substantially all of its crude production to a single company, and began utilizing a broader range of purchasers. In April 2002, Brigham began selling a portion of its oil production to Citation Crude Marketing, Inc. based on an evaluation of terms and capabilities offered by several companies. Brigham's Executive Vice President and CFO and

16. Related Party Transactions (Continued)

board member through July 12, 2002 is the brother of the President of Citation Crude Marketing, Inc., and the son of the President and Chief Executive Officer of Citation Oil & Gas Corporation. Brigham sold approximately 212,000 barrels of oil with a value of $5.6 million to Citation Crude Marketing, Inc. during 2002.

From time to time, in the normal course of business, Brigham has engaged a drilling company in which one of Brigham's current directors owns stock and serves on the board of directors. Total payments to the drilling company during 2002 and 2001 were $0.4 million and $3.9 million, respectively. At December 31, 2002, Brigham owed the drilling company approximately $0.4 million. At December 31, 2001 the drilling company was not performing work for Brigham and there were no amounts owed.

From time to time during 2002, in the normal course of business, Brigham has engaged a service company in which one of Brigham's current directors owns stock and serves on the board of directors. Total payments to the service company during 2002 were $130,000. At December 31, 2002, Brigham owed the service company approximately $76,000. For the year ended December 31, 2001, the service company was not a related party.

In October 2001, Brigham entered into a Joint Exploration Agreement with Carrizo Oil & Gas, Inc. ("Carrizo"). Under the terms of this agreement the parties (1) blended their existing oil and gas leasehold positions covering a South Texas prospect, (2) identified five separate areas of mutual interest within the prospect, and (3) agreed upon procedures for the future exploration and development of the prospect. In November and December of 2002, Brigham and Carrizo entered into agreements that increased Brigham's interest in some of the leasehold within the South Texas prospect. One of Brigham's current directors was a co-founder of Carrizo and is currently chairman of Carrizo's board of directors. At December 31, 2002 and 2001, Brigham was owed $413,000 and $158,000, respectively, by Carrizo for exploration and production activities. Brigham owed Carrizo $11,000 and $13,000 at December 31, 2002 and 2001, respectively.

During 2001, Brigham entered into three agreements with Aspect Resources, LLC ("Aspect"). These agreements included: (1) a Joint Development Agreement extending the term of an area of mutual interest arrangement, and establishing cost sharing for potential expenditures within the project area; (2) an Agreement and Partial Assignment of Seismic Participation Agreement under which Aspect assigned Brigham an interest in an existing 3-D seismic project and Brigham must pay the assigned interest portion of future costs; (3) a Geophysical Exploration Agreement under which Brigham assigned Aspect an interest in an existing 3-D project area (with certain exclusion) and Aspect agreed to provide certain seismic data overlapping the project area and share in future costs. The President of Aspect was a director of Brigham and a member of the Compensation Committee for a portion of 2002 and all of 2001. Total amounts paid to Aspect during 2002 and 2001 for exploration, development and production operations were $189,000 and $588,000, respectively. Total amounts paid to Brigham by Aspect, or on their behalf, during 2002 and 2001 for exploration, development and production operations were $1,008,000 and $524,000, respectively. Brigham owed Aspect $0 and $174,000 at December 31, 2002 and 2001, respectively, for various exploration and production activities. Aspect owed Brigham $312,000 and $291,000 at December 31, 2002 and 2001, respectively, for various oil and gas exploration and production activities. Brigham was also owed $2,800 and $20,000 by Aspect Management Corp., an affiliate of Aspect, at December 31, 2002 and 2001, respectively, for joint venture operations.

17. Supplemental Cash Flow Information

	Year Ended December 31,		
	2002	2001	2000
Cash paid for interest	$3,974	$4,257	$ 3,894
Noncash investing and financing activities:			
Increase in current liabilities for deferred loan fees to be paid in future	—	200	—
Increase in deferred loan fees for issuance of warrants	—	—	2,400
Dividends and accretion on mandatorily redeemable preferred stock	2,952	2,450	275
Conversion of senior credit facility to common stock	10,000	—	—

18. Other Assets and Liabilities

Other current assets consist of the following (in thousands):

	December 31,	
	2002	2001
Gas imbalance receivables	$3,656	$1,537
Deposits	1,909	—
Other	1,078	873
	$6,643	$2,410

Deposits are amounts held by Brigham's derivative counterparty.

Other current liabilities consist of the following (in thousands):

	December 31,	
	2002	2001
Gas imbalance liabilities	$ 5,650	$2,717
Derivative liabilities	3,168	384
Other	1,516	1,414
	$10,334	$4,515

19. Oil and Natural Gas Exploration and Production Activities

Oil and natural gas sales reflect the market prices of net production sold or transferred with appropriate adjustments for royalties, net profits interest and other contractual provisions. Lease operating expenses include lifting costs incurred to operate and maintain productive wells and related equipment including such costs as operating labor, repairs and maintenance, materials, supplies and fuel consumed. Production taxes include production and severance taxes. Depletion of oil and natural gas properties relates to capitalized costs incurred in acquisition, exploration and development activities. Results of operations do not include interest expense and general corporate amounts.

19. Oil and Natural Gas Exploration and Production Activities (Continued)

Costs Incurred and Capitalized Costs

The costs incurred in oil and natural gas acquisition, exploration and development activities follow (in thousands):

	December 31,		
	2002	2001	2000
Costs incurred for the year:			
Exploration	$12,693	$18,210	$14,238
Property acquisition	3,213	3,437	2,540
Development	13,301	14,353	12,555
Proceeds from participants	(703)	(135)	(40)
	$28,504	$35,865	$29,293

Costs incurred represent amounts incurred by Brigham for exploration, property acquisition and development activities. Periodically, Brigham will receive proceeds from participants subsequent to project initiation for an assignment of an interest in the project. These payments are represented by "Proceeds from participants" in the table above.

Following is a summary of capitalized costs (in thousands) excluded from depletion at December 31, 2002 by year incurred. At this time, Brigham is unable to predict either the timing of the inclusion of these costs and the related natural gas and oil reserves in its depletion computation or their potential future impact on depletion rates.

	December 31,			Prior Years	Total
	2002	2001	2000		
Property acquisition	$ 682	$ 565	$195	$11,990	$13,432
Exploration	1,406	418	77	19,838	21,739
Capitalized interest	516	405	15	1,296	2,232
Total	$2,604	$1,388	$287	$33,124	$37,403

20. Oil and Natural Gas Reserves and Related Financial Data (unaudited)

Information with respect to Brigham's oil and natural gas producing activities is presented in the following tables. Reserve quantities, as well as certain information regarding future production and discounted cash flows, were determined by Brigham's independent petroleum consultants and internal petroleum reservoir engineers.

Oil and Natural Gas Reserve Data

The following tables present Brigham's estimates of its proved oil and natural gas reserves. Brigham emphasizes reserves are approximates and are expected to change as additional information becomes available. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Accordingly, there can be no assurance that the reserves set forth herein

20. Oil and Natural Gas Reserves and Related Financial Data (unaudited) (Continued)

will ultimately be produced nor can there be assurance that the proved undeveloped reserves will be developed within the periods anticipated. A substantial portion of the reserve balances was estimated utilizing the volumetric method, as opposed to the production performance method.

	Natural Gas (MMcf)	Oil (MBbls)
Proved reserves at December 31, 1999	65,457	3,027
Revisions of previous estimates	83	(554)
Extensions, discoveries and other additions	17,058	758
Production	(4,431)	(361)
Proved reserves at December 31, 2000	78,167	2,870
Revisions of previous estimates	(1,959)	351
Extensions, discoveries and other additions	22,554	1,101
Sales of minerals-in-place	(3,402)	(106)
Production	(6,766)	(468)
Proved reserves at December 31, 2001	88,594	3,748
Revisions of previous estimates	(824)	(31)
Extensions, discoveries and other additions	18,005	599
Sales of minerals-in-place	(556)	(8)
Production	(5,791)	(701)
Proved reserves at December 31, 2002	99,428	3,607
Proved developed reserves at December 31:		
2000	39,271	1,802
2001	38,633	2,609
2002	42,161	2,330

Proved reserves are estimated quantities of natural gas and crude oil, which geological and engineering data indicate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Standardized Measure of Discounted Future Net Cash Inflows and Changes Therein

The following table presents a standardized measure of discounted future net cash inflows (in thousands) relating to proved oil and natural gas reserves. Future cash flows were computed by applying year-end prices of oil and natural gas relating to Brigham's proved reserves to the estimated year-end quantities of those reserves. Future price changes were considered only to the extent provided by contractual agreements in existence at year-end. Future production and development costs were computed by estimating those expenditures expected to occur in developing and producing the proved oil and natural gas reserves at the end of the year, based on year-end costs. Actual future cash inflows

20. Oil and Natural Gas Reserves and Related Financial Data (unaudited) (Continued)

may vary considerably, and the standardized measure does not necessarily represent the fair value of Brigham's oil and natural gas reserves.

	December 31,		
	2002	2001	2000
Future cash inflows	$ 601,081	$301,201	$ 899,819
Future development and production costs	(131,357)	(84,413)	(154,295)
Future income tax expense	(104,724)	(34,062)	(216,342)
Future net cash inflows	365,000	182,726	529,182
10% annual discount for estimated timing of cash flows	(125,302)	(61,802)	(169,954)
Standardized measure of discounted future net cash flows	$ 239,698	$120,924	$ 359,228

The base sales prices for Brigham's reserves were $4.74 per Mcf for natural gas and $31.25 per Bbl for oil as of December 31, 2002, $2.57 per Mcf for natural gas and $19.84 per Bbl for oil as of December 31, 2001, and $10.42 per Mcf for natural gas and $26.83 per Bbl for oil as of December 31, 2000. These base prices were adjusted to reflect applicable transportation and quality differentials on a well-by-well basis to arrive at realized sales prices used to estimate Brigham's reserves at these dates.

Changes in the future net cash inflows discounted at 10% per annum follow (in thousands):

	December 31,		
	2002	2001	2000
Beginning of period	$120,924	$ 359,228	$ 113,546
Sales of oil and natural gas produced, net of production costs	(31,475)	(27,296)	(15,218)
Development costs incurred	8,625	8,310	5,308
Extensions and discoveries	60,872	41,278	295,239
Sales of minerals-in-place	(1,064)	(22,476)	—
Net change of prices and production costs	136,808	(322,047)	175,018
Change in future development costs	(8,000)	(15,956)	6,990
Changes in production rates and other	(17,003)	(29,545)	(83,322)
Revisions of quantity estimates	(2,876)	(22,676)	(12,262)
Accretion of discount	14,681	49,766	11,447
Change in income taxes	(41,794)	102,338	(137,518)
End of period	$239,698	$ 120,924	$ 359,228

21. Quarterly Financial Data (Unaudited)

	Year Ended December 31, 2002			
	Quarter 1	Quarter 2	Quarter 3	Quarter 4
Revenue	$ 6,444	$8,786	$9,449	$10,497
Operating income	1,016	2,278	3,424	2,717
Net income (loss)	(1,332)	61	989	(294)
Net income (loss) per share:				
Basic	$ (0.08)	$ 0.00	$ 0.06	$ (0.02)
Diluted	$ (0.08)	$ 0.00	$ 0.06	$ (0.02)

	Year Ended December 31, 2001			
	Quarter 1	Quarter 2	Quarter 3	Quarter 4
Revenue	$7,043	$10,504	$8,871	$ 6,130
Operating income (loss)	2,425	4,876	3,296	(572)
Net income (loss)	424	8,327	2,947	(2,460)
Net income (loss) per share:				
Basic	$ 0.03	$ 0.52	$ 0.18	$ (0.15)
Diluted*	$ 0.02	$ 0.30	$ 0.13	$ (0.15)

* As discussed further in Note 10, the diluted earnings per share data for 2001 Quarter 2 and 3 have been restated.

CORPORATE MANAGEMENT

Ben "Bud" M. Brigham

President

Chief Executive Officer

Chairman of the Board

Eugene B. Shepherd, Jr.

Chief Financial Officer

David T. Brigham

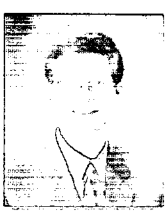
Executive Vice President

Land and Administration

A. Lance Langford

Senior Vice President

Operations



Jeffery E. Larson

Senior Vice President

Exploration

Malcom O. Brown

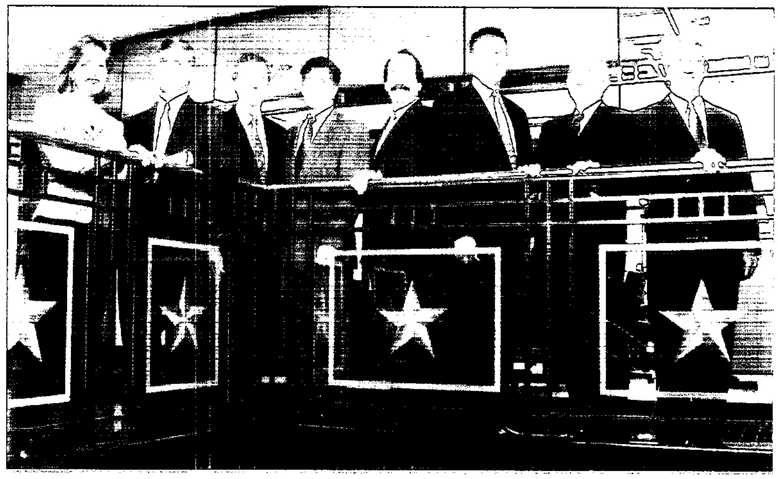
Vice President

Controller

Warren J. Ludlow

General Counsel

Corporate Secretary



Annual Shareholders Meeting

Brigham Exploration Company will hold its annual meeting of shareholders at 1:00 pm on May 28, 2003 at its corporate headquarters in Austin, Texas.

Information Requests

Anyone wishing to obtain more information about Brigham Exploration Company, including copies of Brigham's Form 10-K and other filings with the Securities and Exchange Commission without charge, should direct requests to Investor Relations at 512.427.3444 or visit our website at www.bexp3d.com.

Common Stock Data

Brigham completed its initial public offering of common stock on May 8, 1997. Brigham's common stock trades on The Nasdaq Stock Market under the symbol BEXP.

Forward Looking Statements

Except for the historical information contained herein, the matters discussed in this Annual Report are forward looking statements that are based upon current expectations. Important factors that could cause actual results to differ materially from those in the forward looking statements include risks inherent in exploratory drilling activities, the timing and extent of changes in commodity prices, unforeseen engineering and mechanical or technological difficulties in drilling wells, availability of drilling rigs, land issues, federal and state regulatory developments and other risks more fully described in Brigham's filings with the Securities and Exchange Commission.

Corporate Headquarters

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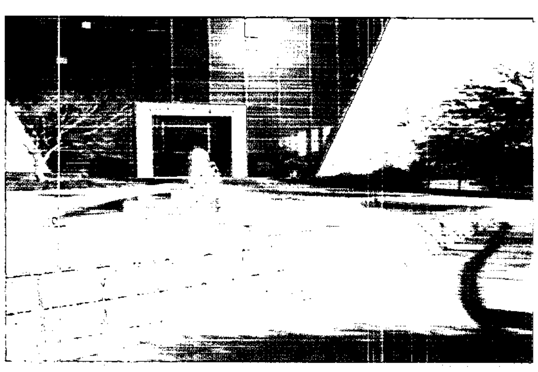

BOARD OF DIRECTORS

(left to right)

Anne L. Brigham
Former Executive Vice President of Brigham Exploration Company

R. Graham Whaling
Chairman and CEO of Laredo Energy, LP

Stephen P. Reynolds
Former President of GAP III Investors, Inc.

Ben "Bud" M. Brigham
President, CEO and Chairman of the Board

Steven A. Webster
Chairman of Global Energy Partners

Stephen C. Hurley
Executive Vice President of Hunt Oil Company

Hobart A. Smith
Consultant for Smith International, Inc.

Harold D. Carter
Former President and Chief Operating Officer of Sabine Corporation

CORPORATE INFORMATION

Independent Auditors

PricewaterhouseCoopers LLP, Dallas, Texas

Legal Counsel

Thompson & Knight L.L.P., Dallas, Texas

Independent Petroleum Engineers

Cawley, Gillespie & Associates, Inc.,
Fort Worth, Texas

Stock Transfer Agent and Registrar

American Stock Transfer and Trust Company
59 Maiden Lane, Plaza Level
New York, NY 10038

BRIGHAM
Exploration Company

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