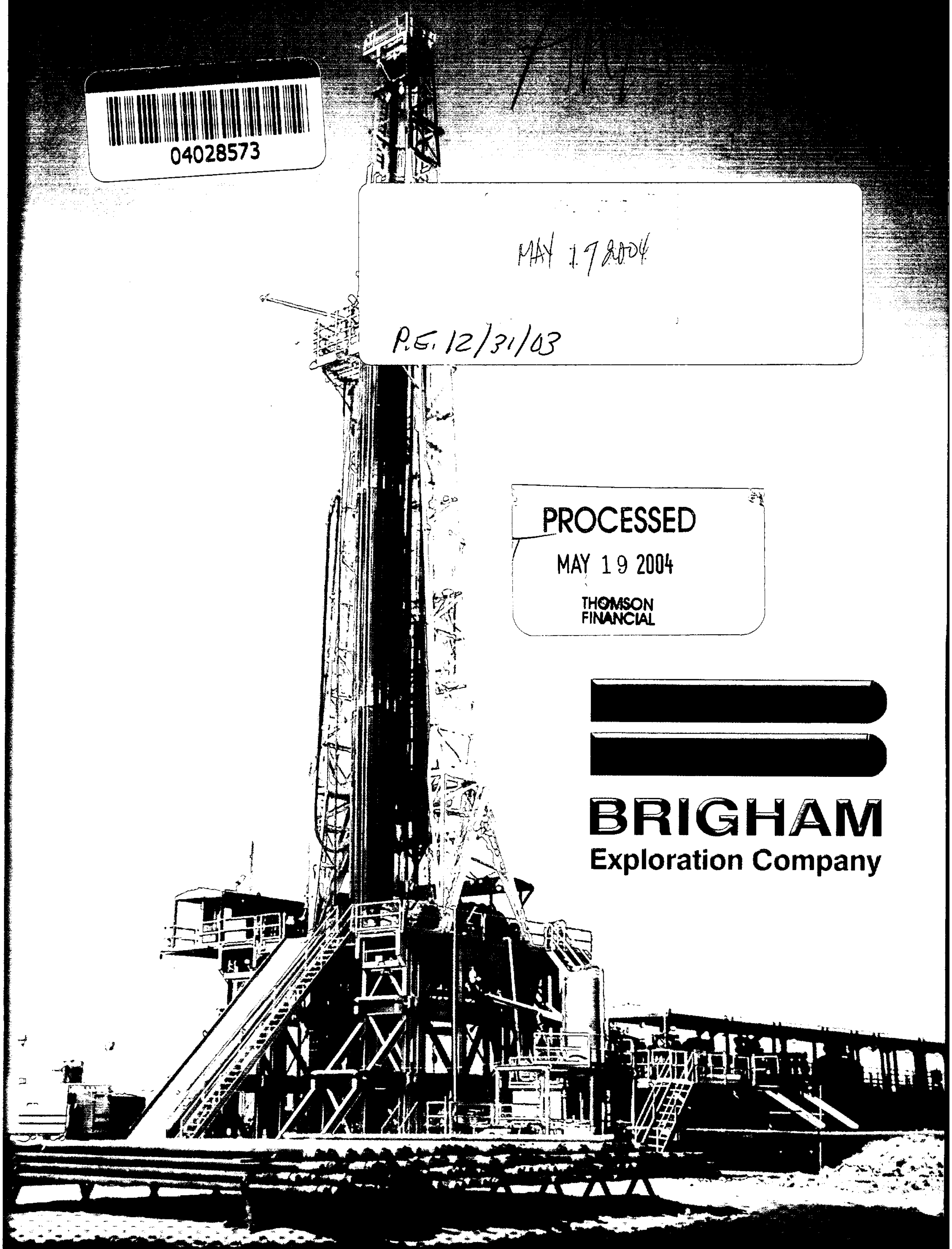


BRIGHAM
Exploration Company

2003 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 twelve geologists and geophysicists, (2) its **knowledge base** derived from its 13 year track record of successful 3-D exploration, including the drilling of 592 3-D delineated wells in its 9,948 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 134 Bcfe** at year-end 2003 that is 82% natural gas and 50% 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) the Texas Gulf Coast, (2) the Anadarko Basin of western Oklahoma and the Texas Panhandle, and (3) West Texas.

1

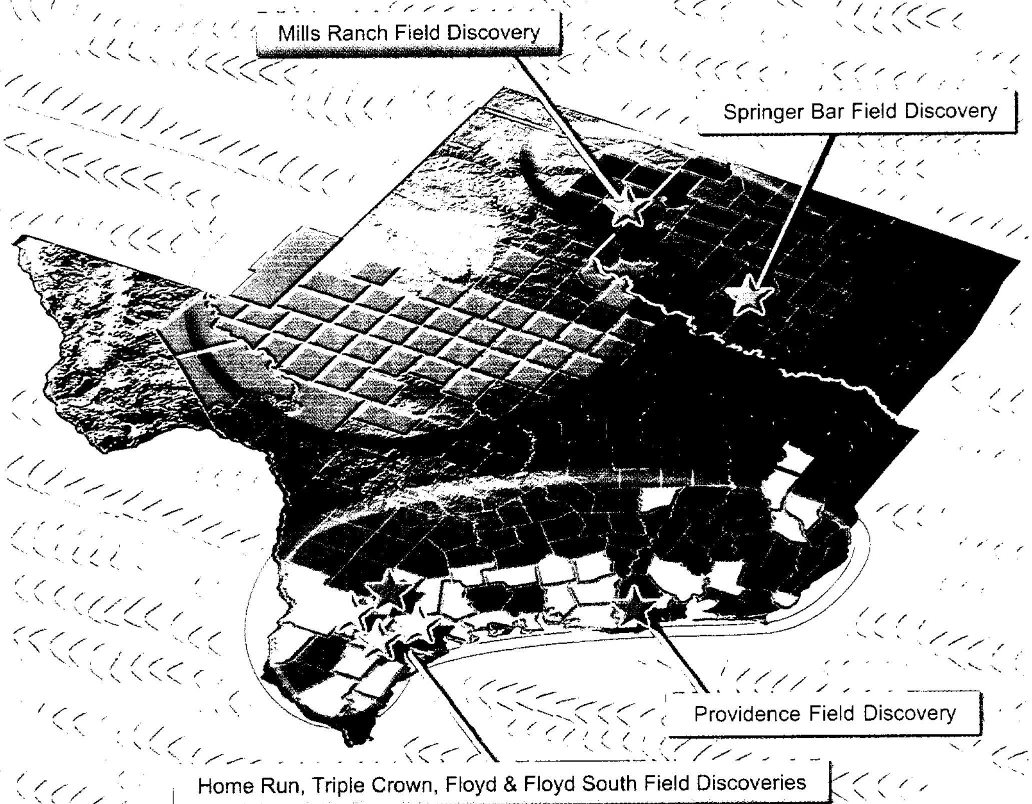
Gulf Coast

Assets at December 31, 2003	
Gross 3-D Sq. Miles	3,456
Net Proved Reserves (Bcfe)	72
Percent Gas	82%
Pre-tax PV10% Value ($MM)	$197
Three Year Results	
Wells Drilled/Completion Rate	41/90%
Avg. Drilling Finding Cost ($/Mcfe)	$1.06

2

Anadarko Basin

Assets at December 31, 2003	
Gross 3-D Sq. Miles	2,204
Net Proved Reserves (Bcfe)	52
Percent Gas	93%
Pre-tax PV10% Value ($MM)	$122
Three Year Results	
Wells Drilled/Completion Rate	35/86%
Avg. Drilling Finding Cost ($/Mcfe)	$1.42



1999
2000
2001
2002
2003

3

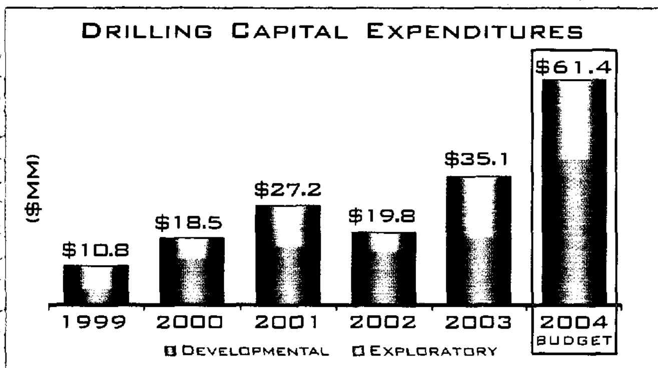
West Texas & Other

Assets at December 31, 2003	
Gross 3-D Sq. Miles	4,288
Net Proved Reserves (Bcfe)	10
Percent Gas	20%
Pre-tax PV10% Value ($MM)	$25
Three Year Results	
Wells Drilled/Completion Rate	17/82%
Avg. Drilling Finding Cost ($/Mcfe)	$0.91

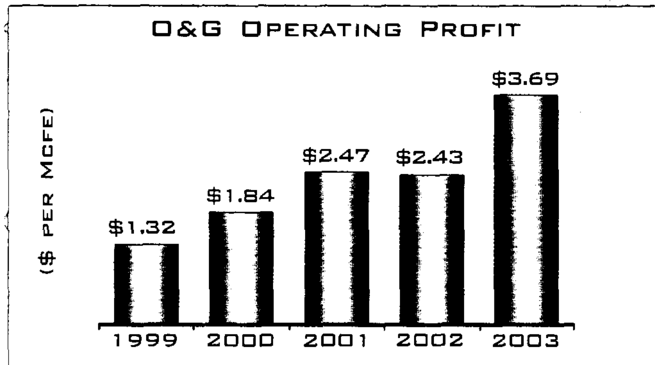
Total Company

Assets at December 31, 2003	
Gross 3-D Sq. Miles	9,948
Net Proved Reserves (Bcfe)	134
Percent Gas	82%
Pre-tax PV10% Value ($MM)	$344
Three Year Results	
Wells Drilled/Completion Rate	93/87%
Avg. Drilling Finding Cost ($/Mcfe)	$1.11

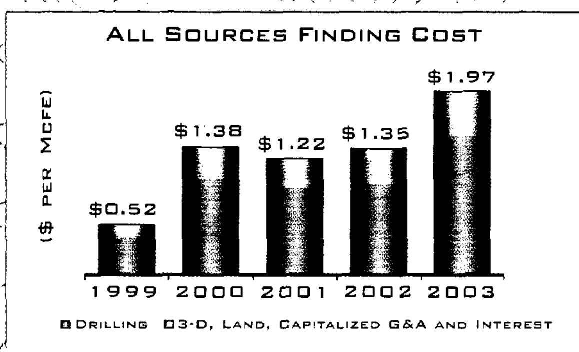
ACCELERATING OPERATIONAL AND FINANCIAL PERFORMANCE

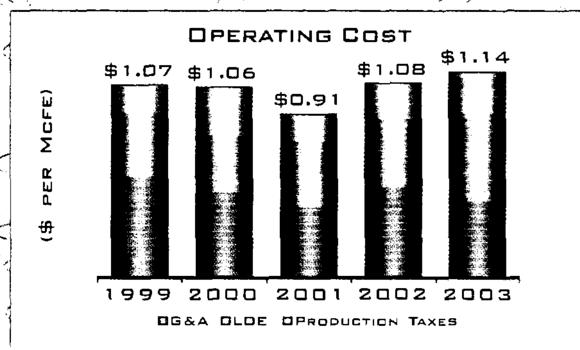


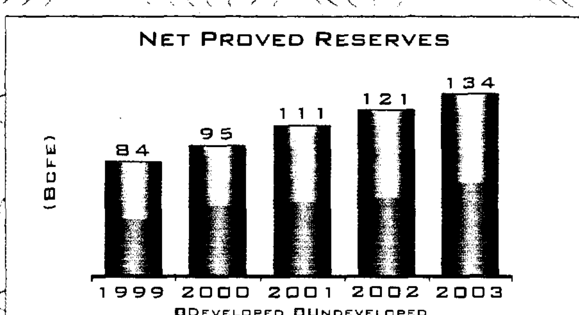
(1) Brigham's beginning fiscal year 2004 drilling CAPEX budget.



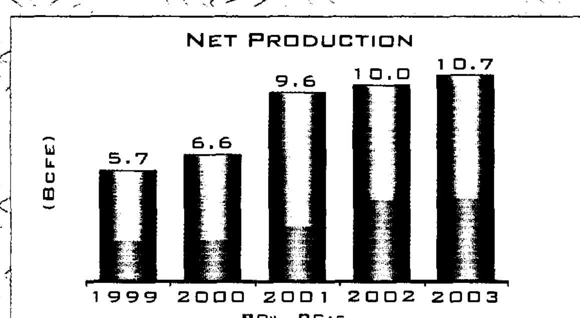
Note: Oil and natural gas revenue less LOE, production taxes and G&A.







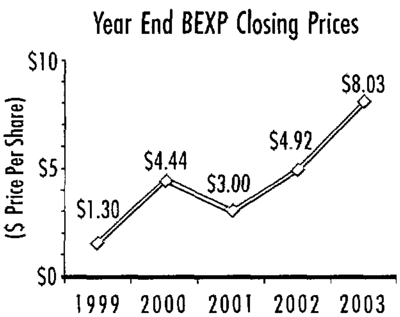
Note: Net proved reserves adjusted to exclude Chitwood/Red Deer Creek properties sold in 1999.

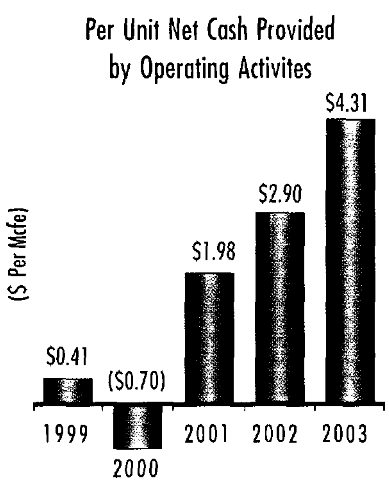


Note: Net production volumes adjusted to exclude Chitwood/Red Deer Creek properties sold in 1999.

LETTER TO SHAREHOLDERS

Ben M. "Bud" Brigham





It is my pleasure to report to our shareholders on our accomplishments during 2003. It was a watershed year for the company in a number of respects, the culmination of a substantial transformation. During 2003 we completed an evolution that began in 1999, from what some viewed as a struggling, purely exploration oriented "semi private" company, that was highly debt levered and operating "under the radar." Today, we are a significantly larger and better known exploration and development company with a long track record of drilling successes, advancing with significant operational and financial momentum.

More specifically, **during the course of 2003 we reduced our debt leverage 46%,** from $0.84 to $0.45 per Mcfe, **while our stock price increased 63%.** Further, **our market capitalization tripled,** from $96 million to $314 million. **Our cash flow increased 87%, while per share earnings increased from a loss of $0.04 to $0.52 per share.** Lastly, given that 2003 was a transformation year for our balance sheet that was not completed until late in the 3rd quarter, our 2003 drilling program did not receive the full benefit of the improvement in our balance sheet. However, **our growth in 2004 should be fully impacted by the improvement in our balance sheet and our $61 million drilling budget, which is roughly three times our 2002 expenditures of approximately $20 million.**

In summary, it was a very busy, but very rewarding year, which I believe **has positioned us to capitalize on a golden opportunity in 2004, to substantially accelerate our growth in shareholder value.** Importantly, given that our accelerated 2004 drilling expenditures will be focused in the same plays with the same substantial component of development drilling spending (67%) as in recent years. Our ability to achieve significant growth in shareholder value will be principally a function of execution risk, without exposing our investors to any new sources of reinvestment risk.

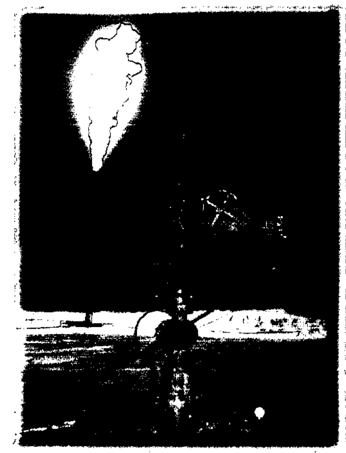
2003 Operational Highlights

During 2003 we grew our proved reserves by 11%. Importantly, approximately 20 Bcfe of the 23.8 Bcfe we added were proved developed, and as a result we grew our proved developed reserves by 20%. These results are a function of our current focus on converting non-producing assets to production and cash flow in this window of strong commodity prices. Our finding and development cost for proved developed reserves was an attractive $1.30 per proved developed Mcfe. However, because we did not add as much in proved undeveloped reserves as we did in proved developed reserves, our all sources total proved finding cost was higher than our historical at $1.97 per Mcfe. **Our three-year average all sources finding cost is now $1.50 per Mcfe,** which I believe is a reasonable expectation for our performance in 2004 and 2005. In general, while I expect our industry's finding costs to continue to trend higher, I also expect that our costs will continue to be low relative to our peers.

Our average daily production in 2003 grew by 7% during the year to a record 29.7 MMcfe per day. With the increase in drilling capital, I expect our production growth to accelerate significantly during 2004. The production growth we achieved during 2003 was in spite of a significant decline in net production volumes from our Providence Field. In January of 2003 our net daily production from the Providence

Field was 14 MMcfe, but by December of 2003 we were only producing roughly 2.5 MMcfe per day. As a result, we lost approximately 11 MMcfe of net daily production over that eleven month period. Despite that historically unusual steep decline in a substantial wedge of our production base, we grew our average daily production sequentially from the 2nd to the 3rd quarter, from the 3rd to the 4th quarter, and by an estimated 10% sequentially from the 4th to the 1st quarter of 2004 (based on our first quarter guidance). Given that, I don't see that unusually steep decline in any significant wedge of our production base as we've moved into 2004, I believe that more of the production we add over the course of 2004 will go towards growth in our company's net production volumes.

Finishing up operationally, **we continued to add to our deep drilling inventory in our focus plays.** For example, during 2003 we successfully negotiated the expansion of our Vicksburg program via new joint ventures at Floyd South, Diablo East and Diablo South, where we retain drilling operations with significantly higher working interests than we retained in our original Diablo Project. To date **we've already had one field discovery, at Floyd South,** as a result of this expansion. Importantly, this discovery continues our string of at least one significant field discovery in each of the past five years.



Well head and gas flare at the Brigham operated Sullivan F #1, the discovery well for Brigham's 2003 Floyd South field discovery.

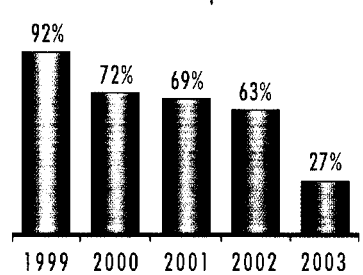
We also added to our drilling inventory in the Frio trend with the completed processing of our recently acquired 3-D seismic data in our General Patton and Bayou Bengal Projects. We're moving quickly to capitalize on this new inventory; to date we've drilled 4 discoveries in 4 attempts in these new projects. Given the drilling inventory we've added in the Frio and the Vicksburg, as well as additional inventory added in our other focus plays, I believe that we did an excellent job in 2003 replacing, and even growing our drilling inventory for production and reserve growth in future years.

2003 Financial Highlights

During the course of 2003 we benefited from some important financial accomplishments, the most important of which was our follow-on equity offering completed in September. I won't go into all of the benefits of the offering, but in general we are clearly enjoying more of the positives associated with being a public company. Most importantly, **the equity offering put us in position, finally, to take greater advantage of our deep and growing inventory of drilling locations - providing us with the opportunity to accelerate the value creation already under way for our shareholders.**

In addition, earlier in 2003 we entered into a new senior credit facility with a very high quality group of financial institutions. Late in the year, given our strong stock price performance, we converted the CSFB preferred stock into common shares. This dramatically simplified our capital structure, while further reducing our debt leverage. As a result of these and other accomplishments, we cut our debt to capitalization by more than half, from roughly 63% as we began the year to 27% at year-end 2003. Looking forward, although our debt levels should increase some during the early stages of our drilling acceleration, we're generally targeting to keep our debt to capitalization at or below 35%.

Debt to Book Capitalization

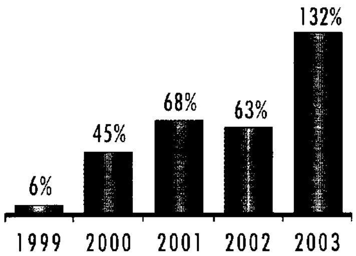


Debt includes book value of Series A and Series B preferred stock.

Finally, we also restructured our subordinated debt ($20 million), which reduced the coupon by roughly 200 basis points and extended the maturity to over five years. Given all of our 2003 accomplishments, we'll benefit in 2004 from both enhanced financial flexibility and substantially reduced interest expenses, positively impacting our cost structure and margins.

LETTER TO SHAREHOLDERS

Return on Investment



ROI calculated as operating profit from oil & gas activities divided by our depletion rate. Operating profit calculated as revenues from the sale of oil and natural gas less cash settlements of derivatives, lease operating expense, production taxes and general & administrative expenses.

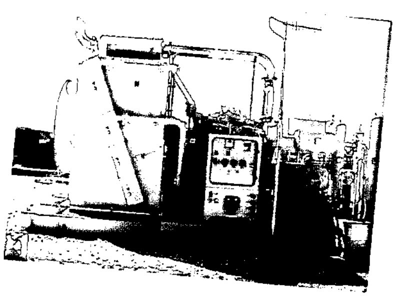
During 2003, as in prior years, we benefited from low lease operating expenses relative to industry. However, due to two relatively expensive workovers they were a little higher than our historical average, at $0.49 per Mcfe relative to $0.38 in 2002. Although we can't anticipate all of the workover requirements during the year, we currently expect our 2004 lease operating expenses to come in lower than that of 2003, thus remaining low relative to our peers.

Looking forward, while industry service costs should rise incrementally over time, I expect Brigham Exploration to continue to benefit from its low cost structure relative to its peers. Importantly, we expect to spend approximately $61 million on drilling in 2004, that's relative to $20 million as recently as 2002, primarily by holding on to higher working interests in our high potential Frio, Vicksburg and Hunton wells. Given this accelerated drilling program, **I expect us to achieve accelerated growth in production volumes in 2004, which should drive our per unit G&A cost down over time.** I believe, that over the next couple of years we can cut our per unit G&A almost in half, from roughly $0.42 per Mcfe in 2003 to around $0.25, positively impacting our cost structure and margins.

Given our low cost structure, and the very strong commodity prices we've enjoyed of late, our margins during 2003 were quite remarkable. **Our operating profit from oil and gas activities in 2003 was $3.69 per Mcfe, which exceeded of our revenue per Mcfe in any of the prior 12 years of our company's history.** Although it's early, thus far 2004 has continued to provide us with record operating margins, benefitting from the continuing strong commodity prices and higher level of production growth.

Importantly, during 2000 to 2002 we generated an attractive ROI (per unit operating profit from oil and gas activities/depletion rate) ranging from 53% to 79%. However, **in 2003 our ROI roughly doubled, to an extremely strong 132%.** Based on our guidance, I expect our ROI in the first quarter of 2004 to expand further, providing us with a running start as we move through 2004.

Therefore, given our strong balance sheet, our current momentum with the drill bit, and our deep and growing inventory of drilling locations, I believe that **the best years for this company are right in front of us. Clearly, we're presented with a "golden opportunity," and we are intently focused on execution, in order to fully capitalize on it.**



Following are key elements of our strategy in 2004:

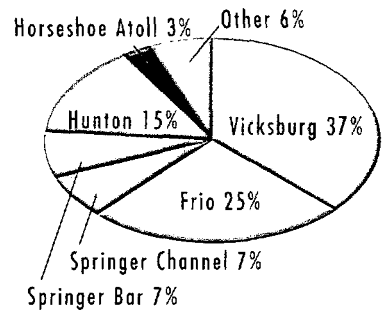
- *<u>First, we'll remain focused.</u> Approximately 94% of our 2004 drilling expenditures are allocated to our deep and growing drilling inventory in our five focus plays, where in recent years we've completed 75 wells in 83 attempts.*

- *<u>Second, we're accelerating our drilling program.</u> Our 2004 budgeted drilling expenditures are up approximately 75% relative to 2003, with 67% of the budget allocated to development drilling and 33% allocated to our 3-D delineated exploratory drilling.*

- *<u>Third, we'll continue our progress in improving cash flow margins and return on invested capital</u> by controlling costs while growing reserves, production and cash flow.*

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		1,880		19/21		$1.01
Vicksburg		218		18/18		$1.54
Vicksburg[1]				14/14		$1.18
Anadarko						
Springer Bar		105		12/14		$0.91
Springer Channel		629		11/15		$1.02
Hunton		762		3/3		$0.92
West Texas						
Horseshoe Atoll		1,049		12/12		$0.60
Total or Average		4,643		75/83		$1.00[1]

2004 Budgeted Drilling CAPEX by Trend

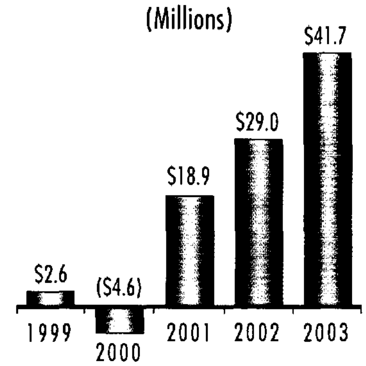


In closing, those who follow us know that the strategies outlined above are not new, they're essentially the same strategies we've followed for five years now. In fact, our business model is fundamentally the same as it was at our inception in 1990, fourteen years ago. In my view, it's our consistent dedication to this strategy, and more importantly, the outstanding execution of it by our employees, that has positioned us to capitalize on the golden opportunity in front of us. I could not be prouder of how far we've come, particularly given the challenges we faced in earlier years.

Furthermore, although we started from scratch, and have come a long way, I believe we are now in the "sweet spot" for a growing a company with the drill bit. Recent history, over the last ten years or so, has provided a number of very good "drill bit driven" examples of successful growth. I believe that this is primarily due to the size of reserve targets we're drilling for domestically. In my view, we're sized right, and now capitalized right, to potentially double, and possibly even triple our production volumes over the next two to three years. Again, it's now all about execution.

To all of our dedicated employees, to our loyal business partners, and to our longstanding and new fellow shareholders, I say "THANK YOU." You've set the stage for what should be an exciting and rewarding 2004.

Net Cash Provided by Operating Activites (Millions)



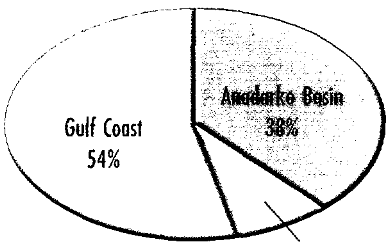
Ben M. Brigham
Chairman of the Board
President and Chief Executive Officer
April 29, 2004

[1] *Excluding four early wells with completion problems prior to changed operational procedures.*

OVERVIEW

We are an independent exploration and production company that applies 3-D seismic imaging and other advanced technologies to systematically explore for and develop onshore oil and natural gas reserves in the United States. Our activities are concentrated in the onshore Texas Gulf Coast, the Anadarko Basin and West Texas, in trends that are conducive to multi-well, repeatable drilling programs.

Reserve Mix



2003 Information:	Gulf Coast	Anadarko Basin	West Texas
Drilling CAPEX	**$24.6**	**$9.0**	**$1.5**
Net Land & Seismic	**4.4**	**1.2**	**—**
Total E&D	**$29.0**	**$10.2**	**$1.5**
Wells Drilled	17	15	5
Average WI%	56%	33%	28%
Average Daily Production	18.3	6.7	4.7
Pre-tax PV10% Value	$196.8	$122.3	$24.7
2004 Budget:			
Drilling CAPEX	**$38.9**	**$20.8**	**$1.7**
Net Land & Seismic	**9.9**	**1.5**	**0.6**
Total E&D	**$48.8**	**$22.3**	**$2.3**
Wells Drilled	25	29	5
Average WI%	56%	29%	48%

Onshore Texas Gulf Coast: VICKSBURG TREND

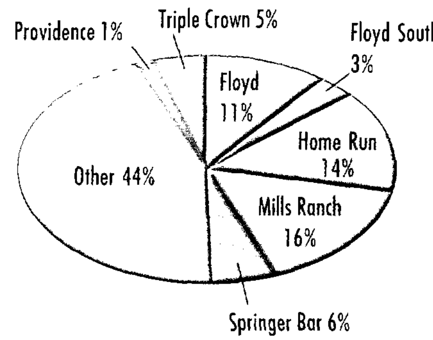
Since 1999, we have focused our exploration efforts in the Vicksburg trend on our Diablo Project area, located in Brooks County of South Texas, where we have completed 18 wells in 19 recent attempts. Initially we owned a 34% working interest in our Diablo Project, with another industry participant owning the remaining 66%, and together we controlled approximately 8,000 acres of leasehold. In November 2003, we significantly expanded our ownership in this area when we signed two new joint venture agreements with the same industry participant. The new joint ventures cover an additional 5,150 acres and enable us to retain higher working interests, ranging from 50% to 100%, while also retaining all the associated drilling and completion operations.

Our strategy in the Vicksburg is focused on adding value through drilling in our deep developmental inventory, while also expanding this inventory through exploration. Our exploration efforts in the Vicksburg have generated four discoveries at Home Run, Triple Crown, Floyd Fault Block and Floyd South. We believe that these field discoveries have provided us with a substantial inventory of development locations consisting of both proved undeveloped and non-proved drilling locations. During 2004 we plan to drill six of these development wells, as well as two higher risk but higher reserve potential exploratory wells. Based on our initial 2004 drilling budget, we are forecasting to spend approximately $22.8 million of our 2004 drilling expenditures in the Vicksburg. We believe we have a multi-year inventory of locations in the Vicksburg, and we therefore expect to continue to direct a significant portion of our future capital expenditures towards both proved and non-proved drilling opportunities in this area.

Home Run & Triple Crown Fields

We discovered the Home Run Field in late 1999 and the Triple Crown Field in 2001. As of December 31, 2003, we had drilled and completed fourteen consecutive wells in these fields with an average working interest of 42%. For 2004, we expect to drill three wells within the Home Run Field and one well within the Triple Crown Field. We believe that these fields could require up to 45 additional wells, eleven of which were classified as proved undeveloped at December 31, 2003.

Pre-tax PV10% Value by Field

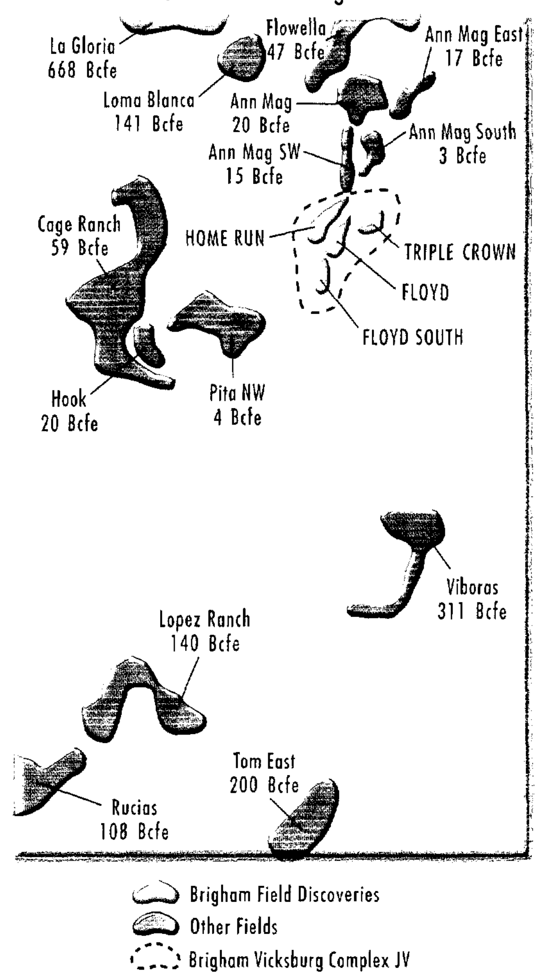


Floyd Fault Block Field

We drilled the discovery well for this field, the Sullivan #8, in December 2002. We retained a 34% working and 25% revenue interest in the well, which 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 three times that encountered in our typical Home Run Field well.

As of December 31, 2003, we had completed three wells in the Floyd Fault Block Field. We estimate that up to seven additional wells will be required to develop this field, four of which were classified as proved undeveloped locations at December 31, 2003. We expect to drill two additional wells within the Floyd Fault Block Field in 2004.

South Texas Vicksburg Trend



Floyd South Fault Block Field

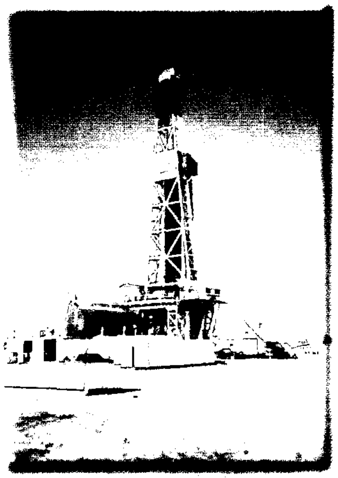
We drilled the discovery well for this field, the D.J. Sullivan F #1, in December 2003. This was the first well drilled as part of our new Vicksburg joint ventures entered into in November 2003. We operated the Sullivan F #1 and retained a working interest of 100% before and 50% after casing point. We plan to commence drilling the first development well in the field during the second quarter of 2004. We will retain a 50% working interest before and after casing point in the first development well and any other wells subsequently drilled in the field. We believe that the Floyd South Fault Block Field could require three to six wells, three of which were classified as proved undeveloped at December 31, 2003.

Additional Vicksburg Opportunities

Prior to drilling the Sullivan E #1 in early 2004, we had drilled and completed a total of 18 wells in 18 attempts in the Vicksburg. The Sullivan E #1 was the second well drilled as part of our new Vicksburg joint ventures and was drilled to test the Diablo East fault block. Despite encountering a significant interval of gas bearing sands, it was determined that the prospective zones were tight and the well was plugged and abandoned. We are currently evaluating the results from the well and at present have no plans to drill a second well in the Diablo East fault block.

In addition to our current joint venture activity, we are also evaluating several additional Vicksburg structures outside of our joint ventures, but within the vicinity of our Diablo Project.

Onshore Texas Gulf Coast: FRIO TREND



In the Frio, we have accumulated an inventory of over 1,880 square miles of both proprietary and non-proprietary 3-D seismic data located primarily in Brazoria, Calhoun, Matagorda, and Jackson counties in the Upper Texas Gulf Coast. We are targeting both the shallow, non-pressured and the deeper pressured Frio sands.

Since late 2000, we have completed 19 wells in 21 attempts in the Frio, and in 2001 we discovered our prolific Providence Field. For 2004 we estimate we will spend approximately $15.6 million of our forecasted 2004 drilling expenditures, to drill 16 wells in the Frio trend with an average working interest of 67%.

General Patton Project

In early 2003, 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 Providence Field. We sold a 50% working interest in the project to another industry participant on a promoted basis. As a result, we paid 33% of the seismic and pre-seismic land costs for our 50% working interest in the project, while also retaining operational control.

We began interpreting the data in May 2003 and commenced our drilling program in this project in August 2003 with the drilling of the Harriman #1. We retained a 39% revenue interest in the well, which began producing in October 2003 at an initial rate of approximately 5.2 MMcfe per day.

The Harrison #1, our second well in the project, began producing in February 2004 at an initial rate of approximately 2.9 MMcfe per day. The Harrison #1 may set up one to two development locations, both of which may be drilled during 2004. To date, we have completed two wells in two attempts in the project and expect to drill approximately seven wells in the project during 2004.

Bayou Bengal Project

In late 2003 and early 2004 we acquired approximately 77 square miles of existing 3-D seismic data and 54 square miles of new proprietary 3-D seismic data along the same trend that has provided most of our recent Frio discoveries. We sold a 25% working interest in the project to an industry participant on a promoted basis. As a result, we paid 60% of the seismic and pre-seismic land costs for our 75% interest in the project, while also retaining operational control.

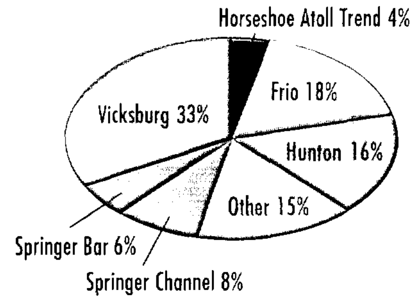
Pontoon drills working on Bayou Bengal Project.

We commenced drilling our first well in this project during October 2003. The Trull B #2 was completed to sales in January 2004 at a pipeline constrained initial rate of approximately 2.5 MMcfe per day. We retained 75% working and 56% revenue interest in this shallow Frio discovery.

The Sartwelle #1, our second well in this project, commenced production to sales in February 2004 at an initial rate of approximately 4.2 MMcfe per day. We retained a 63% working and 47% revenue interest in the Sartwelle #1.

We have completed two wells in two attempts in our Bayou Bengal Project, and currently expect to drill five additional wells during 2004.

PV10% by Focus Play



Additional Frio

We continue to generate additional drilling inventory from our 3-D seismic database in the Frio trend. Historically, approximately 20% of our exploration wells in the Frio trend have targeted higher risk, higher reserve potential objectives. One of our higher risk, but higher potential tests was our 2001 Staubach #1 well, the discovery well for our Providence Field, now a five well field. However, as in recent years, the vast majority of our Frio exploration wells are expected to test relatively lower risk, primarily amplitude defined prospects. In recent years these prospects have provided us with a high success rate and a high rate of return on our drilling capital investments.

We also continue to add to our drilling inventory in the Frio by assembling several new proprietary 3-D seismic projects. We expect to commence acquisition of one to two additional proprietary 3-D projects in the third quarter of 2004, in which we plan to retain at least 50% working interest in the projects.

Anadarko Basin: SPRINGER BAR TREND

Grady County Springer Bar Field

We have approximately 105 square miles of 3-D seismic data and together with our participants control over 10,000 leasehold acres in one of the most prolific producing areas of the Anadarko Basin.

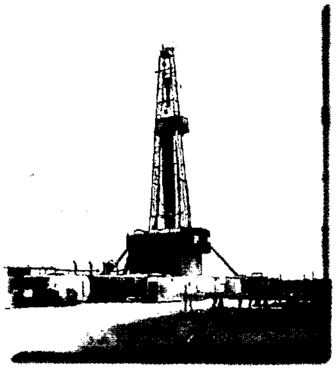
In 2000, based on our 3-D seismic interpretation, we discovered a large, stratigraphically defined Springer Bar field with the successful completion of the Nix #1 well. To date we have completed 12 wells in 14 attempts in this field.

Successful wells drilled in the field have produced at initial rates ranging from 2 to 8 MMcfe per day, and generally exhibit lower production decline rates relative to our wells in the onshore Texas Gulf Coast. Given our drilling success to date in the field, we are currently budgeting to spend approximately $4.3 million of our 2004 drilling expenditures to drill twelve development wells with an average working interest of 10%. We believe this field could require 18 additional wells for full development, 9 of which were classified as proved undeveloped at December 31, 2003.

Anadarko Basin: SPRINGER CHANNEL TREND

Our 3-D seismic inventory in the Springer Channel trend consists of over 629 square miles of 3-D seismic data covering portions of Dewey, Blaine, Canadian, Grady and Caddo Counties, Oklahoma. Our activities in this area target buried fluvial sand channels at depths of 9,000 to 12,000 feet, as well as other secondary objectives.

We have completed 11 wells in 15 attempts in the Springer Channel trend since 2000. In 2003, we invested approximately $1.1 million in this trend to drill and complete five wells with an average working interest of 47%. For 2004, we currently expect to spend approximately $4.2 million of our 2004 drilling expenditures to drill 10 wells in the Springer Channel trend with an average working interest of 36%.



Brigham operated Eula Clay #1 well drilling in the Hunton Trend.

Anadarko Basin: HUNTON TREND

Our 3-D seismic inventory in the Hunton trend consists of approximately 762 square miles of 3-D seismic data covering portions of Wheeler, Hemphill and Roberts Counties, Texas and Beckham County, Oklahoma. The primary exploration targets in this area are high potential, multi-well structural features at depths ranging from 7,500 to 25,000 feet. The trend has historically provided longer life reserves relative to our typical onshore Texas Gulf Coast wells. For 2004, we have budgeted approximately $9.2 million of our 2004 drilling expenditures to drill three wells in the Hunton trend with an average working interest of 64%.

Mills Ranch Field

The Mills Ranch #1, the discovery well for this field, began 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 as of year-end 2003 had produced 4.1 Bcfe and was producing approximately 1.3 MMcf of natural gas equivalents per day.

We commenced drilling the Mills Ranch #1-99S in February 2004. This well is a re-entry and sidetrack of a well previously drilled by another operator. We retain a 92% working interest in the well, though we may promote out a 25% working interest to an industry participant. The Mills Ranch #1-99S is located several miles to the east of the Mills Ranch #1 and #2 wells. There are currently three producing wells on this large structure, including our Mills Ranch #1 and #2 on the west side, that have produced over 21 Bcfe to date.

We plan to use the same drilling rig that is currently drilling the Mills Ranch #1-99S, to drill two additional deep Hunton and Arbuckle wells during 2004. At least one of these wells will be a development well on the west side of the Mills Ranch Field.

We believe the Mills Ranch Field could require up to seven additional wells for full development, three of which were classified as proved undeveloped at December 31, 2003.

($000, except per share and per Mcfe data)	Year Ended December 31, 1999	2000	2001	2002	2003
Operating Data:					
Revenue from the sale oil and natural gas	$14,992	$19,143	$32,293	$35,100	$51,545
Total revenue	15,277	19,212	32,548	35,176	51,677
Operating income *(loss)*	(11,944)[a]	3,647	10,025	9,435	21,757
Net cash provided *(used)* by operating activities	2,578	(4,635)	18,922	28,973	41,691
Net income *(loss)* to common stockholders	(21,628)[a]	16,337[b]	9,238	(576)	14,842
Per Diluted Share Data:					
Weighted average shares outstanding *(000)*	14,152	16,241	28,205	16,138	34,354
Net income *(loss)* per share	($1.53)[a]	$1.01[b]	$0.44[c]	($0.04)	$0.52[d]
Oil & Natural Gas Capital Expenditure Data:					
Net land and G&G	($2,569)	$583	$2,560	$2,831	$5,647
Net drilling	10,817	18,461	27,209	19,800	35,106
Property acquisitions *(sales)*	(17,071)	-	(207)	(604)	-
Capitalized G&A and interest	6,559	6,300	6,050	5,657	6,081
Total net capital expenditures	($2,264)	$25,344	$35,612	$27,684	$46,834
Summary Balance Sheet Data:					
Cash and cash equivalents	$2,742	$837	$5,112	$15,318	$5,779
Oil and natural gas properties, net	112,066	129,490	151,891	164,980	197,311
Total assets	125,683	146,911	173,075	202,059	224,216
Total debt	97,341	82,000	91,721	81,797	39,000
Series A preferred stock[e]	-	8,558	16,614	19,540	8,794
Series B preferred stock[f]	-	-	-	4,777	-
Stockholders' equity	8,998	34,757	49,601	61,749	138,345
Per Mcfe Data:					
Revenue from the sale of oil and natural gas	$2.39	$2.90	$3.37	$3.51	$4.83
Other revenue	0.05	0.01	0.03	0.01	0.01
Total revenue	$2.44	$2.91	$3.40	$3.52	$4.84
Lease operating expenses	0.36	0.32	0.37	0.38	0.49
Production taxes	0.15	0.27	0.16	0.20	0.23
G&A expenses	0.56	0.47	0.42	0.50	0.42
Gross profit	$1.37	$1.85	$2.45	$2.44	$3.70

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

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

(c) Weighted average shares outstanding includes 11 million shares of common stock related to convertible debt and warrants related to Series A preferred stock 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 earnings per share amounts. Weighted average shares oustanding includes 1.2 million shares related to warrants and options that were deemed common stock equivalents under the "Treasury Method."

(d) Excludes a $268,000 ($0.01 per diluted share) gain related to cumulative change in accounting principle.

(e) Year end liquidation value of Series A preferred stock was $20 million in 2000, $32.6 million in 2001, $35.3 million in 2002 and $8.8 million in 2003.

(f) Year end liquidation value of Series B preferred stock was $10 million 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, 2003

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 twelve 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 30, 2003, the registrant had 20,562,410 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 30, 2003 of $5.01 per share as reported on The Nasdaq Stock Market℠, was $50.5 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 26, 2004, the registrant had 39,562,696 shares of voting common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the Registrant's 2004 Annual Meeting of Stockholders to be held on June 3, 2004, 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, 2003.

TABLE OF CONTENTS

BRIGHAM EXPLORATION COMPANY

2003 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 activities in provinces where we believe 3-D seismic technology can be used effectively to maximize our return on invested capital by reducing drilling risk and enhancing our ability to grow reserves and production volumes in a cost-effective manner. Our exploration and development activities are concentrated in three provinces: the onshore Texas Gulf Coast, the Anadarko Basin and West Texas.

Since our inception in 1990, we have evolved from a pioneering, 3-D seismic-driven exploration company to a balanced exploration and development company with technical and operational expertise and a strong production base. We benefit from our focus in five proven and complementary onshore trends contained within our three core provinces, which provides us with diversification in our drilling investments. We believe that our five focus trends provide us with a broad range of risk profiles and reserve potentials for both natural gas and oil prospects and associated geographical and operational diversification. As a result, we are not dependent on our continued drilling success in a single core trend. Instead, in any given year our overall results may be positively impacted by the results in one or several of our focus trends. We believe that this diversification and our knowledge base in these trends, as demonstrated by our track record, are significant distinguishing factors for us.

We have generated a multi-year inventory of exploration prospects, which, due to our field discoveries, are complemented by a multi-year inventory of development locations. Since our inception through December 31, 2003, we have drilled 592 wells, consisting of 453 exploratory and 139 development wells with an aggregate completion rate of 69% and an average all-sources finding cost of $1.41 per Mcfe. In 2003 we spent $46.8 million in net capital expenditures on oil and gas activities and achieved an all-sources finding cost of $1.97 per Mcfe. Additionally, we completed 33 out of 37 wells drilled in 2003 replacing 223% of our 2003 production. To further capitalize on our multi-year inventory of exploration and development prospects, we currently plan to significantly increase our oil and gas capital expenditures in 2004 to approximately $78.9 million, representing a 69% increase over 2003 oil and gas capital expenditures.

We have accumulated 3-D seismic data covering approximately 9,948 square miles (6.4 million acres) in over 28 geologic trends in seven provinces and seven states. We focus our 3-D seismic acquisition efforts 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 592 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.

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 certain of our 2004 projects, based upon our improved capital availability. For example, approximately 37% of our budgeted 2004 drilling expenditures are allocated to the Vicksburg trend, where we expect to retain an average working interest of 61% (relative to our historical average working interest of 40% through 2003). Further, approximately 25% of our budgeted

2004 drilling expenditures are allocated to the Frio trend, where we expect to retain an average working interest of 55% (relative to our historical average working interest of 47% through 2003).

Business Strategy

Our business strategy is to create stockholder value by growing reserves, production volumes and cash flow through exploration and development drilling in areas where we believe our operations will likely result in a high return on our invested capital. Key elements of our business strategy include:

- *Focus on Core Provinces and Trends.* We have accumulated and continue to add to a multi-year inventory of 3-D seismic and geologic data and have developed a strong technical knowledge base in the following geologic trends within our core provinces: 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.

Further, we believe our focus on these five proven onshore trends within our three core provinces provides us with important drilling investment diversification. Since 1999, our drilling success in these trends has resulted in six significant field discoveries and a multi-year inventory of development drilling locations. We plan to focus a majority of our near term capital expenditures in these trends, 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, to generate and maintain a large multi-year inventory of high quality exploratory prospects. Our highly skilled staff of twelve geophysicists and geologists generates substantially all of our prospects. We do not rely on third party generated opportunities, which usually involve the payment of consideration over and above the costs incurred to generate and drill the prospect. We believe that our six field discoveries and our history of achieving low all-sources finding costs over the last three, five and seven years, averaging $1.50, $1.25 and $1.42 per Mcfe, respectively, reflect the quality and depth of our 3-D delineated prospect inventory as well our ability to continue to generate such opportunities.

- *Capitalize on Exploration Successes Through Development of Field Discoveries.* From 1990 to 1999, we grew our reserves and production volumes primarily through successful 3-D delineated exploration drilling. Due to our exploratory drilling success and the resulting growth in our inventory of development drilling locations, approximately 60% of our drilling capital expenditures in 2001, 2002 and 2003 were developmental. We believe our ability to balance our higher risk exploratory drilling with lower risk development drilling has reduced our risk profile. For 2004, we intend to allocate approximately 64% of our total drilling expenditures for development drilling. See "Item 2. Properties" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — 2004 Outlook" for additional discussion about capital expenditures for 2004.

- *Accelerate Drilling of Our Prospect Inventory.* To capitalize on our multi-year inventory of exploration and development locations, our goal is to substantially increase our drilling activity in 2004. In 2004 we have budgeted $61.4 million in drilling capital expenditures, representing a 75% increase over amounts spent in 2003. See "Item 2. Properties" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — 2004 Outlook" for additional discussion about capital expenditures for 2004.

- *Enhance Returns Through Operational Control.* We seek to maintain operational control of our exploration and drilling activities. As an operator, we retain more control over the timing and selection of drilling prospects, which enhances our ability to optimize our finding and development costs and to maximize our return on invested capital. Since we generate substantially all of our projects, we generally have the ability to retain operational control over all phases of our exploration and development activities. As of December 31, 2003, we operated approximately 62% of the pre-tax PV-10% value of our proved developed reserves. Further, in 2003 we operated 46% of the wells we drilled, representing 70% of our drilling capital expenditures, and we expect to operate the majority of the wells planned for 2004.

Exploration and Development Staff

Our experienced exploration staff includes six geophysicists, six geologists, two computer applications specialists and two geophysical/geological/engineering technicians. Our geologists and 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 geophysicists and geologists have an average of more than 20 years of experience per person. We assembled our team 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.

Our land department staff includes four landmen with an average of more than 21 years of experience primarily within our core provinces and three lease and division order analysts. Our land department contributed to pioneering many of the innovations that have facilitated exploration using large 3-D seismic projects.

Oil and Natural Gas Market and Major Customers

Our natural gas produced in the onshore Texas Gulf Coast is sold to various purchasers including intrastate pipeline purchasers, operators of processing plants, and marketing companies under both monthly spot market contracts and multi-year arrangements. The vast majority of our natural gas sales are based on related natural gas index pricing, and in some cases our gas is processed at a plant and we receive a percentage of the value of natural gas liquids recovered.

Our markets for natural gas produced in the Anadarko Basin are operators of processing plants and marketing companies. We sell gas under both monthly spot market contracts and multi-year contracts, which are normally based on related natural gas index pricing. Some of our gas is processed and we receive a percentage of the value of natural gas liquids recovered.

Most of our natural gas in West Texas is sold to purchasers who process our natural gas under multi-year contracts and pay us a percentage of the value they receive from the resale of the natural gas liquids and the remaining residue gas.

We sell our crude oil and condensate at the lease to a variety of purchasers at prevailing market prices under short-term contracts that normally provide for us to receive an applicable posted price plus a market-based bonus.

Since 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 — Oil And Natural Gas Prices Fluctuate Widely And Low Prices Could Have A Material Adverse Impact On Our Business And Financial Results By Limiting Our Liquidity And Flexibility To Accelerate Our Drilling Program" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Risk Factors — The Marketability Of Our Natural Gas

Production Depends On Facilities That We Typically Do Not Own Or Control Which Could Result In A Curtailment Of Production And Revenues." For the year ended December 31, 2001, sales to Lantern Petroleum Corporation and Highland Energy Company 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 so that we could 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 we do. 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 Many Of Our Competitors Have Resources In Excess Of Our Available Resources" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Risk Factors — We Have Substantial Capital Requirements For Which We May Not Be Able To Obtain Adequate Financing."

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 That May Not Result In Commercially Productive Reserves And May Require Expenditures In Excess Of Budgeted Amounts."

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 those of 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 damage 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 Operating And Other Casualty Risks That Could Result In Liability Exposure Or The Loss Of Production And Revenues" 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 All Of The Risks We Face, Which Could Result In Significant Financial Exposure."

Employees

On March 26, 2004, we had 55 full-time employees and two part-time employees. None of these employees are represented by any labor union and we believe relations with them 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.

Governmental Regulation

Our oil and natural gas exploration, production, transportation and marketing activities are subject to extensive laws, rules and regulations promulgated by federal and state legislatures and agencies, including the Federal Energy Regulatory Commission (FERC), the Environmental Protection Agency, the Texas Commission on Environmental Quality (TCEQ), the Texas Railroad Commission and the Oklahoma Corporation Commission. 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 do not own or operate any pipelines or facilities that are directly regulated by FERC, its regulation of third party pipelines and facilities could indirectly affect our ability to transport or market our production. Moreover, FERC has in the past, and could in the future impose price controls on the sale of natural gas. In addition, we believe we are in substantial compliance with all applicable laws and regulations, however, 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 states of Texas and Oklahoma, 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 and sulfur dioxide) 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 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.

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 46% of the gross wells and 69% of the net wells that we drilled during 2003, as compared with 10% of the gross wells and 17% of the net wells we drilled during 1996. As a result of our increased operational control in recent years, wells operated by us constituted 62% of the pre-tax PV-10% value of our proved developed reserves at year-end 2003, as compared to only 5% at year-end 1996.

Our operations staff includes five engineers who have drilling, reservoir, environmental and operations engineering experience primarily within our three core provinces. These engineers work closely with our geologist and geophysicist 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.

Website Access to Company Reports

We make available free of charge through our website, www.bexp3d.com, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with the Securities and Exchange Commission. Information on our website is not a part of this report.

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 effectively used to maximize our return on capital invested by reducing drilling risk and enhancing our ability to cost-effectively grow reserves and production volumes.

For the three-year period ended December 31, 2003, we completed 81 gross wells (30.4 net) in 93 attempts for a completion rate of 87% at an average all-sources finding cost of $1.50 per Mcfe. We have budgeted approximately $61.4 million to drill approximately 36 development wells and 23 exploratory wells during 2004. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — 2004 Outlook." The following is a summary of our properties by major province as of December 31, 2003, unless otherwise noted:

	Year Ended December 31, 2003		At December 31, 2003					
Province	Drilling Capital Expenditures (Millions)	Average Daily Production (MMcfe/d)	Proved Reserves (Bcfe)	Pre-tax PV-10%(a) (Millions)	% Natural Gas	Productive Wells Gross	Productive Wells Net	3-D Seismic Data (Sq. Miles)
Texas Gulf Coast	$24.6	18.3	72.3	$196.8	82%	62	19.2	3,456
Anadarko Basin	9.0	6.7	51.7	122.3	93%	122	28.5	2,204
West Texas/Other	1.5	4.7	10.2	24.7	20%	98	26.9	4,288
Total	$35.1	29.7	134.2	$343.8	82%	282	74.6	9,948

(a) Standardized measure at December 31, 2003, was $261.6 million.

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. In addition, certain sand reservoirs display seismic "bright spots," which can be direct hydrocarbon indicators and can result in greatly reduced drilling risk. However, "bright spots" are not always reliable as direct hydrocarbon indicators and do not generally assess reservoir productivity. We believe our established 3-D seismic exploration approach, combined with our exploration staff's extensive experience in the Texas Gulf Coast and accumulated knowledge base in this province, particularly given our recent drilling successes, provides us with significant competitive advantages. The majority of our Texas Gulf Coast activity is currently concentrated in the Vicksburg and Frio trends.

Over the past three years we have spent approximately 68% of our total capital expenditures for drilling, land and geological and geophysical in the onshore Texas Gulf Coast region and have completed 37 gross wells (15.6 net) in 41 attempts for a completion rate of 90%. Production from the onshore Texas Gulf Coast region represented 61% of our average daily production in 2003, up from 41% in 2001.

During 2003, we completed 15 gross wells (8.2 net) in 17 attempts for a completion rate of 88% in the onshore Texas Gulf Coast. We operated 12 of the 17 wells that we drilled. Eleven of the wells we drilled were exploratory and six were developmental. Our development drilling was focused in the Providence, Home Run and Floyd Fault Block Fields. In addition, we made a new Vicksburg field discovery with the successful completion of our Floyd South Fault Block Field discovery well.

For 2004, we intend to focus our drilling activity in this province on the development of our Home Run, Triple Crown, Floyd Fault Block and Floyd South Field discoveries in the Vicksburg, the further development of our Providence Field in the Frio and the continued drilling of our 3-D delineated exploration inventory in the Vicksburg and Frio trends. We expect to spend approximately $38.9 million to drill 25 wells in the onshore Texas Gulf Coast. Approximately 52% percent of these drilling capital expenditures are budgeted for development drilling activities, with the remainder allocated towards exploration drilling.

Vicksburg Trend

Since 1999, our exploration efforts in the Vicksburg trend have been focused in the general area of our Diablo Project located in the Brooks County area of South Texas. At inception we owned a 34% working interest in the Diablo Project, with another industry participant owning the remaining 66%. Prior to November 2003, we had approximately 8,000 acres of leasehold and 218 square miles of 3-D seismic data in the area.

In November 2003, we significantly expanded our ownership in this area when we signed two new joint ventures with our same industry participant covering an additional 5,150 acres, increasing our total acreage under control in the area to approximately 13,150 acres. In the new joint ventures we have the opportunity to retain larger working interests, ranging from 50% to 100%, while also retaining all the associated drilling and completion operations.

As of December 31, 2003, we had completed 18 wells in 18 attempts in the Vicksburg trend and generated four significant discoveries at the Home Run Field, the Triple Crown Field, the Floyd Fault Block Field and the Floyd South Fault Block Field. The primary objectives within this area are large structural features at depths ranging from 9,000 to 14,000 feet.

We believe that we have a substantial multi-year inventory of proved undeveloped and non-proved Vicksburg drilling locations in our Home Run, Triple Crown, Floyd Fault Block and Floyd South Fault Block Fields, and other adjacent fault blocks.

In 2003 we invested approximately $10.9 million to drill and complete five wells in the Vicksburg with an average working interest of 50%. For 2004 we plan to devote approximately $22.8 million in drilling capital expenditures to drill six development wells and two exploratory wells in the Vicksburg. We expect to direct a significant portion of our future capital expenditures towards both proved and non-proved drilling opportunities in this area.

Floyd Fault Block. We drilled our Floyd Fault Block discovery well, the Sullivan #8, in December 2002. We retained a 34% working and 25% revenue interest in the Sullivan #8, which proved 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 three times that encountered in our typical Home Run Field well.

The Sullivan #8 began producing in March 2003 at a rate of approximately 9.2 MMcf of natural gas and 580 barrels of condensate per day (12.7 MMcfe/d) or approximately 3.2 MMcfe/d net to our 25% revenue interest. After producing approximately 2.9 Bcfe, in October 2003 the well stopped producing due to an apparent blockage above the producing formation. Prior to the blockage, the Sullivan #8 was producing 7.7 MMcf of natural gas and 400 barrels of condensate per day (10.1 MMcfe/d). In February 2004, the operator of the well reestablished production at approximately 2.5 MMcf of natural gas and 100 barrels of condensate per day (3.1 MMcfe/d). It is uncertain how long the Sullivan #8 will continue to produce in its current state. If the well stops producing in the future, it is highly likely that the well will be sidetracked or redrilled.

We retained a 34% working interest and 25% net revenue interest in the Sullivan #9 and the Sullivan #10, the first two development wells in our Floyd Fault Block Field. The most recent well, the Sullivan #10, encountered approximately 187 feet of apparent net pay, and was completed and fracture stimulated. The Sullivan #10 commenced production at an initial rate of approximately 11.9 MMcf of natural gas and 689 barrels of condensate per day (16.0 MMcfe/d) or approximately 3.9 MMcfe/d net to our revenue interest, with a flowing tubing pressure of approximately 8250 psi. We estimate that up to seven additional wells will be required for full development of the Floyd Fault Block Field, four of which were classified as proved undeveloped locations at December 31, 2003. We expect to drill two additional wells within the Floyd Fault Block Field in 2004.

Home Run Field & Triple Crown Field. We discovered the Home Run Field in late 1999 and the Triple Crown Field in 2001. As of December 31, 2003, we had drilled and completed 14 consecutive wells in these fields with an average working interest of 42%. During 2003, we drilled and completed two wells in the Home Run Field and expect to drill up to three wells within the Home Run Field and one well within the Triple Crown Field in 2004. We believe that the Home Run and Triple Crown Fields could require up to 45 additional wells for full development, eleven of which were classified as proved undeveloped at December 31, 2003.

Floyd South Fault Block Field. We drilled our Floyd South Fault Block Field discovery well, the D.J. Sullivan F#1, in December 2003. The Sullivan F #1, which was drilled to a total depth of 14,177 feet, was the first well to test the Floyd South fault block as part of the new Vicksburg joint venture entered into in 2003 with our industry participant. The Sullivan F#1 encountered approximately 55 feet of apparent net pay in the Lower Vicksburg and commenced production to sales in January 2003 at a rate of approximately 6.7 MMcf of natural gas and 293 barrels of condensate per day (8.5 MMcfe/d) with a flowing tubing pressure of 8100 psi, or approximately 3.3 MMcfe/d net to our 39% revenue interest. We operated the drilling of the Sullivan F #1, retaining a working interest of 100% before and 50% after casing point. We currently plan to commence drilling the first development well in the Floyd South Fault Block Field during the second quarter of 2004. We will retain a 50% working interest before and after casing point in the first development well and any other wells subsequently drilled in the Floyd South Fault Block Field. We believe that the Floyd South Fault Block Field could require three to six wells for full development, three of which were classified as proved undeveloped at December 31, 2003.

Adjacent Fault Blocks to Prior Field Discoveries. In early 2004, the Sullivan E #1 was drilled to a total depth of 14,650 feet to test the Diablo East fault block as part of our new Vicksburg joint ventures. Despite encountering over 400 gross feet of what was apparently gas bearing sands, it was determined that the prospective zones were tight and the well was plugged and abandoned. We are evaluating the results of this well to determine if another test of the Diablo East fault block is merited. Prior to drilling the Sullivan E #1, we had completed eighteen consecutive Vicksburg wells in four different fault blocks.

We have additional unproven fault blocks to test, most of which are adjacent to our prior discoveries.

Additional Vicksburg Potential. We continue to generate prospects in the Vicksburg trend, and seek to continue to expand our operations in this core trend, which is currently the single most important of the five focus trends.

Frio Trend

In the Frio trend of the Upper Texas Gulf Coast, we have accumulated an inventory of over 1,880 square miles (1.2 million acres) of predominantly non-proprietary 3-D seismic data located primarily in Brazoria, Calhoun, Matagorda, and Jackson Counties in the Upper Texas Gulf Coast. Within this trend we are targeting both the shallow non-pressured and the deeper pressured Frio sands. Reservoirs in this trend can display seismic "bright spots," which can be direct hydrocarbon indicators and can result in greatly reduced drilling risk. However, "bright spots" are not always reliable as direct hydrocarbon indicators and do not generally assess reservoir productivity.

Since late 2000, we have completed 19 wells in 21 attempts in the Frio trend and discovered our prolific Providence Field. In 2003 we invested approximately $13 million in the Frio trend to drill 11 wells, 10 of which were completed. Our average working interest in these wells was 61%. For 2004 we estimate that our drilling expenditures will be approximately $15.6 million to drill five development wells with an average working interest of 52% and eleven exploratory wells with an average working interest of 57%.

Providence Frio Field. We discovered the Providence Field during the fourth quarter of 2001, when we drilled and completed the Staubach #1. Including the Staubach #1 discovery well in 2001, we have now completed five wells in five attempts in the Providence Field with an average working interest of 40%.

During 2002 and 2003 we invested approximately $7.5 million in the drilling of our Providence Field, which generated approximately $24 million in net revenue during this time period. During 2004 we expect to drill one to two additional wells in the Providence Field.

General Patton Project. In early 2003, 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 Providence Field. We sold a 50% working interest in the project to participants 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 operational control. We began interpreting the data in May 2003 and commenced our drilling program in this project in August 2003 with the drilling of the Harriman #1 discovery. We operated and retained a 50% working and 39% revenue interest in the Harriman #1, which commenced production in early October 2003 at an initial rate of approximately 4.9 MMcf of natural gas and 50 barrels of oil per day (5.2 MMcfe/d).

In October 2003, we commenced drilling our second General Patton Project well, the Harrison #1, to test our Corner Pocket Prospect. In February 2004, the Harrison #1 commenced production at an initial rate of approximately 2.2 MMcf of natural gas and 113 barrels of oil per day (2.9 MMcfe/d). We retained a 50% working interest in the Harrison #1, which may set up one to two offsets that will be drilled during 2004. To date, we have completed two wells in two attempts in our General Patton Project, and currently expect to drill approximately eight General Patton Frio wells during 2004.

Bayou Bengal Project. In late 2003 and early 2004 we acquired approximately 77 square miles of existing non-proprietary and 54 square miles of new proprietary 3-D seismic data in our Bayou Bengal Project. This project is located along the same trend that has provided most of our recent Frio discoveries. We sold a 25% working interest in the project to a participant on a promoted basis. As a result, we paid 60% of the seismic and pre-seismic land costs for our 75% interest in the project, while also retaining operational control. We commenced drilling our first well in this project, the Trull B #2, during October 2003. The Trull B #2, which targeted a total depth of 9,500 feet, was completed to sales in January 2004 at an initial rate of approximately 2.3 MMcf of natural gas and 34 barrels of oil per day (2.5 MMcfe/d). This production rate was constrained due to limited pipeline capacity. We retained a 75% working and 56% revenue interest in this shallow Frio discovery.

In December 2003, we drilled the Sartwelle #1, our second discovery in our Bayou Bengal Project. The Sartwelle #1 commenced production to sales in February 2004 at an initial rate of approximately 4.0 MMcf of natural gas and 42 barrels of oil per day (4.2 MMcfe/d) with a flowing tubing pressure of 4750 psi. We retained a 63% working and 47% revenue interest in the Sartwelle #1, which was drilled to a total depth of approximately 10,450 feet. To date, we have completed two wells in two attempts in our Bayou Bengal Project, and currently expect to drill two additional wells during 2004.

Other Frio. In February 2004 we completed the Randall #1 in the Lower Frio at an initial rate of approximately 2.0 MMcf of natural gas and 12 barrels of oil per day (2.1 MMcfe/d) with a flowing tubing pressure of 6700 psi. We operated the Randall #1 with a 94% working and 70% revenue interest, which was drilled to a total depth of approximately 14,200 feet. We believe that the Randall #1 could set up one additional offset, which we expect to commence later in 2004.

In addition to our ongoing drilling program in the Frio trend, we continue to generate additional drilling inventory from our 3-D seismic database of more than 1,880 square miles in this trend. Historically, approximately 20% of our exploration wells targeted higher risk, higher reserve potential objectives. The Staubach #1 discovery well for our Providence Field is an example of a successful higher potential Frio test. However, as in recent years, the vast majority of our Frio exploration wells are expected to test relatively lower risk, primarily amplitude defined prospects. In recent years these prospects have provided us with a high success rate and a high rate of return on our drilling capital investments.

We also continue to add to our drilling inventory in the Frio by assembling several new proprietary 3-D seismic projects in the same trend where we have experienced significant drilling success in recent years. We expect to commence acquisition of at least one additional proprietary 3-D project in the third quarter of 2004.

Other Texas Gulf Coast

The Dinn Ranch Field. The Dinn Ranch Field is a Wilcox discovery located in Duval County, Texas. We own interests in two wells within the field. The first well, the Lopez #1, experienced operational difficulties, but was eventually completed as a marginal producer. The second well, the Lopez #3, was producing in February 2003 at a rate of approximately 16.5 MMcf of natural gas per day. The Lopez #3 had produced approximately 2.9 Bcfe through December 31, 2003, and was producing approximately 6.3 MMcf of natural gas per day at year-end. We retain 2% overriding royalty interests in these two wells that convert to working interests at different payouts. In each of these two wells, we will own a 12.5% working interest at 100% payout, which will increase to a 25% working interest at 200% payout. Payout occurs at the point in time when the net proceeds from the sale of production from the well equals all of the costs and expenses associated with the drilling and operation of the well. We expect a third well to spud late in 2004, in which we plan 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 producing province offers a combination of lower risk exploration and development opportunities in shallower horizons, as well as higher reserve potential in the deeper sections that have been relatively under explored.

We believe our drilling programs in the Anadarko Basin and West Texas generally provide us with longer life reserves and help to balance our drilling program in the prolific, but generally shorter reserve life, onshore Texas Gulf Coast province.

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 recent activity has been focused primarily in the Springer Channel and Hunton trends. However, given the recent success of development wells in a Springer Bar Field, discovered by us in late 2000, developmental activity in this field accelerated during 2003.

Over the past three years we have spent approximately 25% of our total capital expenditures for drilling, land and geological and geophysical in the Anadarko Basin and have completed 30 gross wells (9.6 net) in 35 attempts for a completion rate of 86%. Production from the Anadarko Basin represented 23% of our average daily production in 2003, down from 38% in 2001.

During 2003, we completed 14 gross wells (4.8 net) in 15 attempts for a completion rate of 93%. We operated four of the wells that we drilled in the Anadarko Basin in 2003. Seven of the wells we drilled were exploratory and eight were developmental.

For 2004, 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 $20.8 million to drill 29 wells. Approximately 90% of these drilling capital expenditures are budgeted for development drilling activities, with the remainder allocated towards exploration drilling.

Grady County Springer Bar Field

In Grady County, Oklahoma we have approximately 105 square miles (67,200 acres) of 3-D seismic data and together with our participants control over 10,000 leasehold acres in one of the most prolific producing areas of the Anadarko Basin. In 2000, based on our seismic interpretation of this data, we discovered a large, stratigraphically defined Springer Bar field with the successful completion of the Nix #1 in the Britt interval of the Springer formation. In late 2000, we confirmed the field with the

Pitchford #1 well, which produced from the same Britt interval at a depth of approximately 14,550 feet. We own a 17.35% working interest in the Nix #1 and a 32.27% working interest in the Pitchford #1.

During 2003, we invested approximately $2.6 million in this area and completed 6 gross wells (1.1 net) in 7 attempts. Successful wells drilled in the field have produced at initial rates generally ranging from 2 to 8 MMcfe per day, with low production decline rates relative to our onshore Texas Gulf Coast wells. Given our drilling success to date in the field, we are currently budgeting to spend $4.3 million to drill twelve development wells with an average working interest of 10% in this area in 2004.

In early 2003 we participated in the successful drilling of the McCasland Farms #2, which commenced production in May at an initial rate of approximately 4.5 MMcf of natural gas and 50 barrels of oil per day (4.8 MMcfe/d), or approximately 0.9 MMcfe/d net to our 18.6% revenue interest. We also participated with a 15% working interest in the Stonehocker #1, which began producing to sales in July 2003 at a rate of approximately 7.0 MMcf of natural gas per day, or approximately 0.8 MMcfe/d net to our 12% revenue interest.

The Jones #2 commenced drilling in June 2003, and was subsequently completed to sales in October 2003 at a rate of approximately 7.0 MMcf of natural gas and 100 barrels of oil per day (7.6 MMcfe/d), or 1.2 MMcfe/d net to our 15.9% revenue interest. During September 2003, we participated in the Teel #1 with a 16% working interest, which commenced producing to sales in December 2003 at a rate of approximately 6.9 MMcf of natural gas and 30 barrels of oil per day (7.1 MMcfe/d), or 0.9 MMcfe/d net to our 13% revenue interest. In November 2003, we participated in the drilling of the Mack Farms #1 with a 14.6% working interest. In February 2004, the Mack Farms #1 was being completed to sales after encountering approximately 55 feet of apparent net pay in various Springer intervals.

Other Grady County Activity

In April 2003, we participated in the Palmer #1 with a 29% working interest. The Palmer #1 was completed and fracture stimulated in the Bromide formation and initially produced at a rate of approximately 130 barrels of oil and 350 Mcf of natural gas per day (1.1 MMcfe/d) or 0.2 MMcfe/d net to our 22% revenue interest. In November 2003, we participated with a 33% working interest in the Cooper #1, which was drilled to a depth of approximately 16,374 feet and encountered approximately 65 feet of apparent net pay in the Bromide formation. The Cooper #1 was being completed in February 2004, with production to sales expected in March 2004. We are also participating with a 29% working interest in the Burton #1, another Bromide test that commenced drilling in March 2004. Results for the Burton #1 are expected in late May 2004.

Springer Channel Trend

Our 3-D seismic inventory in the Springer Channel trend consists of over 629 square miles (402,560 acres) of 3-D seismic data covering portions of Dewey, Blaine, Canadian, Grady and Caddo Counties, Oklahoma. Our activities in this area target buried fluvial sand channels at depths of 9,000 to 12,000 feet, as well as other secondary objectives. Since 2000, we have completed 11 wells in 15 attempts in the Springer Channel trend. In 2003 we invested approximately $1.1 million in this trend to drill and complete five wells in 2003 with an average working interest of 47%.

During 2003 we participated in an 8,800 feet Springer test, the Bryson #1, with a 36% working interest. The Bryson #1 was completed in the Springer interval in July 2003 at a rate of approximately 2.5 MMcf of natural gas and 110 barrels of oil per day (3.1 MMcfe/d), or approximately 0.9 MMcfe/d net to our 29% revenue interest. We have budgeted approximately $4.2 million to drill four development wells with an average working interest of 53% and six exploratory wells with an average working interest of 21% in this trend in 2004.

Hunton Trend

Our 3-D seismic inventory in the Hunton trend consists of approximately 762 square miles (487,680 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, multi-well structural features at depths ranging from 7,500 to 25,000 feet. The trend has historically provided longer life reserves relative to our typical onshore Texas Gulf Coast wells. For 2004, we have budgeted approximately $9.2 million to drill three development wells in the Hunton trend with an average working interest of 64%.

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 this well with a 64% working interest. The Mills Ranch #1 paid out its drilling and completion costs during its first year of production, and at year-end 2003 had produced 4.1 Bcfe and was producing approximately 1.3 MMcfe/d. 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 well, 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 and perforating and stimulating 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, and the well was put on production at an initial rate of approximately 2.0 MMcfe/d.

We believe that the Mills Ranch Field could require up to seven additional wells for full development, three of which were classified as proved undeveloped at December 31, 2003. Drilling operations commenced in February 2004 on one of the proved undeveloped locations, the Mills Ranch #1-99S. The Mills Ranch #1-99S is a reentry and sidetrack of a well previously drilled by another operator. We expect to retain at least a 68% working interest in the well, which is located several miles to the east of the Mills Ranch #1 and #2 wells. Currently there are three producing wells on the large structure, including our Mills Ranch #1 and #2 on the west side. The three producing wells on this structure have produced over 21 Bcfe to date. Subsequent to drilling the Mills Ranch #1-99S, we plan to utilize the same large drilling rig to drill two additional deep Hunton and Arbuckle wells during 2004. At least one of these wells will be a development well on the west side of the field.

Other Hunton Trend. We continue generating additional high potential opportunities within the Hunton trend, including prospects with substantial reserve potential in the stratigraphically deeper Arbuckle formation. The Arbuckle is a several thousand-foot carbonate interval that has been productive in a number of fields with significant cumulative production in the area. However, the presence of a large carbonate Arbuckle interval does not insure the presence of hydrocarbons, which in most cases will be dependent upon the presence of a fault, change in stratigraphy or other hydrocarbon trapping mechanism. The drilling depths for the Arbuckle vary widely within the trend, from as shallow as 10,000 feet to depths as great as 25,000 feet.

West Texas

West Texas is predominantly an oil producing province with generally longer lived reserves than that of the onshore Texas Gulf Coast. Our drilling activity in our West Texas province has been focused primarily in 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 depths ranging from 7,000 to 13,000 feet.

Over the past three years, we have spent approximately 7% of our total capital expenditures for drilling, land and geological and geophysical in West Texas and have completed 14 gross wells (5.2 net) in 17 attempts for a completion rate of 82%. Production from West Texas represented 16% of our average daily production in 2003 down from 21% in 2001.

During 2003 we completed four gross wells (1.3 net) in five attempts for a completion rate of 80%. We operated one of the five wells that we drilled in West Texas in 2003. Four of the wells we drilled were exploratory and one was developmental.

For 2004, 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. For 2004, we expect to spend approximately $1.7 million to drill one development well with a working interest of 40% and four exploratory wells with an average working interest of 51%.

Horseshoe Atoll Trend

We have an inventory of approximately 1,049 square miles (671,360 acres) of 3-D seismic data primarily covering significant 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 12 gross wells in 12 attempts in the trend with an average working interest of 44%.

3-D Seismic Exploration

We have accumulated 3-D seismic data covering approximately 9,948 square miles (6.4 million acres) in over 28 geologic trends 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 592 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 we believe are best suited for 3-D seismic exploration. 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 computer-aided exploration 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 were 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. In 2003 and early 2004, we acquired approximately 77 square miles of non-proprietary and 54 square miles of new proprietary 3-D seismic data in our Bayou Bengal Project, also located in the Frio trend of the Upper Texas Gulf Coast. We sold a working interest in Bayou Bengal to an industry participant on a promoted basis and retained a 75% working interest in the project. In 2004, we expect to acquire approximately 267 square miles of new proprietary 3-D seismic data within our core areas.

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 burdens, which we believe do not materially interfere with the use of or affect the value of such properties. Our senior credit facility and senior subordinated notes are secured by first and second liens, respectively, against substantially all of our proved oil and natural gas properties. 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."

Oil and Natural Gas Reserves

Our estimated total net proved reserves of oil and natural gas as of December 31, 2003, 2002 and 2001 and the present values attributable to these reserves as of those dates were as follows:

	At December 31,		
	2003	2002	2001
Estimated Net Proved Reserves:			
Natural gas (MMcf)	109,403	99,428	88,594
Oil (MBbls)	4,130	3,607	3,748
Natural gas equivalent (MMcfe)	134,182	121,070	111,081
Proved developed reserves as a percentage of net proved reserves	50%	46%	49%
Pre-tax PV-10% (in thousands)	$343,813	$307,374	$146,807
Standardized measure (in thousands)	$261,598	$239,698	$120,924
Base price used to calculate reserves(a):			
Natural gas (per MMbtu)	$ 5.83	$ 4.74	$ 2.57
Oil (per Bbl)	$ 32.55	$ 31.25	$ 19.84

(a) 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 Securities and Exchange Commission, 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 there from 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 the Cawley, Gillespie report represents 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,					
	2003(a)		2002(b)		2001(c)	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Natural gas	12	6.3	4	0.9	5	1.6
Oil	4	1.3	6	0.9	4	2.6
Non-productive	5	1.8	1	0.7	6	1.3
Total	21	9.4	11	2.5	15	5.5
Development wells:						
Natural gas	11	3.9	7	2.4	15	4.6
Oil	1	0.4	4	1.7	2	1.1
Non-productive	3	1.8	1	0.3	0	0.0
Total	15	6.1	12	4.4	17	5.7

(a) Excludes one (0.5 net) exploration well that is under evaluation and temporarily abandoned.

(b) Excludes one (0.2 net) development well that is productive but was temporarily abandoned. There are no current plans to put this well on production.

(c) Excludes one (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.

We do not own drilling rigs and the majority of our drilling activities have been conducted by independent contractors or by industry participant operators under standard drilling contracts.

Productive Wells and Acreage

Productive Wells

The following table sets forth our ownership interest at December 31, 2003 in productive oil and natural gas wells in the areas indicated.

	Natural Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Texas Gulf Coast	43	14.6	19	4.6	62	19.2
Anadarko Basin	103	23.7	19	4.8	122	28.5
West Texas	15	1.7	83	25.2	98	26.9
Total	161	40.0	121	34.6	282	74.6

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, 2003:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Texas Gulf Coast	9,785	3,468	16,948	8,097	26,733	11,565
Anadarko Basin	40,006	14,215	37,278	19,598	77,284	33,813
West Texas	9,681	3,034	9,006	4,365	18,687	7,399
Other	1,521	686	3,483	1,225	5,004	1,911
Total	60,993	21,403	66,715	33,285	127,708	54,688

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, 2004	39,850	13,320
December 31, 2005	12,885	6,749
December 31, 2006	12,244	8,564
Thereafter	323	321
Total	65,302	28,954

In addition, as of December 31, 2003, we had lease options to acquire additional acres. The following table sets forth the year in which our options expire and the gross and net acres we have under option:

	Acres Expiring	
Twelve Months Ending:	Gross	Net
December 31, 2004	22,401	13,338
December 31, 2005	6,482	459
Total	28,883	13,797

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,		
	2003	2002	2001
Production:			
Natural gas (MMcf)	6,356	5,791	6,766
Oil (MBbls)	720	701	468
Natural gas equivalent (MMcfe)	10,674	9,996	9,573
Average sales price per unit:			
Natural gas revenues (per Mcf)	$ 5.68	$ 3.33	$ 4.29
Effects of hedging activities (per Mcf)	(0.76)	(0.12)	(1.18)
Average price (per Mcf)	$ 4.92	$ 3.21	$ 3.11
Oil revenues (per Bbl)	$ 30.79	$25.17	$24.38
Effects of hedging activities (per Bbl)	(2.62)	(1.62)	(0.33)
Average price (per Bbl)	$ 28.17	$23.55	$24.05
Total natural gas and oil revenues (per Mcfe)	$ 5.46	$ 3.70	$ 4.22
Effects of hedging activities (per Mcfe)	(0.63)	(0.19)	(0.85)
Average price (per Mcfe)	$ 4.83	$ 3.51	$ 3.37
Average production costs:			
Lease operating expenses (per Mcfe)	$ 0.43	$ 0.31	$ 0.32
Ad valorem taxes (per Mcfe)	0.06	0.06	0.05
Production taxes (per Mcfe)	0.23	0.20	0.16

Costs Incurred

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

	Year Ended December 31,		
	2003(a)	2002(b)	2001(c)
	(Dollars in thousands)		
Exploration	$20,732	$12,693	$18,210
Property acquisition	5,037	3,213	3,437
Development	22,285	13,301	14,353
Proceeds from participants	(793)	(703)	(135)
Costs incurred	$47,261	$28,504	$35,865

(a) Excludes $427,000 of proceeds from the sale of interests in properties, projects and prospects in 2003.

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

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

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, management does not expect these matters to have a materially adverse effect on our financial condition, results of operations or cash flows.

On November 20, 2001, we filed a lawsuit in the District Court of Travis County, Texas, against Steve Massey Company, Inc. The Petition claims Massey furnished defective casing to us, which ultimately led to the casing failure of our Palmer 347 #5 well and the loss of the Palmer #5 as a producing well. In 2004, the parties agreed in principle to settle the case on terms favorable to us. We will receive approximately $440,000 as a result of this settlement. The amount of the settlement will reduce capitalized well cost. In addition, Massey has agreed to drop its $445,819 counterclaim.

On July 11, 2002, an employee of a contractor on our Burkhart #1-R location, Matagorda County, Texas, was involved in a fatal accident. The United States Department of Labor Occupational Safety & Health Administration conducted an inspection and we settled all issues resulting from that inspection for $70,000 in October 2003.

On October 8, 2002, relatives of the contractor's employee filed a wrongful death action against us and three other contractors in the District Court of Matagorda County, Texas. On March 23, 2004, a jury determined that we had no liability in the accidental death of the contractor's employee.

In September 2002, we filed suit in the District Court of Matagorda County, Texas, against one of our contractors in connection with the drilling of the Burkhart #1-R well, claiming that contractor breached its contract with us and negligently performed services on the well. We believe the contractor's actions damaged us by approximately $650,000. The contractor counterclaimed, claiming it is entitled to recover approximately $315,000. In February 2004, the parties agreed in principle to settle the case. The settlement will result in a payment by the contractor to our co-participants and us. In addition, the contractor will drop its counterclaim. Based on the amount of the settlement, the additional costs that were covered by insurance, and the insurer being subrogated to our claim, we will not receive any incremental recovery as a result of the settlement.

Prior to drilling, the operator of the Stonehocker #1 well disputed our ownership in the well. In March 2003, a Motion to Determine election was filed with the Oklahoma Corporation Commission. In January 2004, an Administrative Law Judge with the Oklahoma Corporation Commission ruled in our favor. The operator of the Stonehocker #1 appealed the ruling and the Appellate Referee with the Oklahoma Corporation Commission affirmed the original ruling in March 2004. The full Commission Panel will review the reports of the Referee and the original Administrative Law Judge and either approve or modify the report. An order will then be issued reflecting the Oklahoma Corporation Commission ruling. The operator will then have 30 days from the date of the final order to file an appeal with the Oklahoma Supreme Court.

A company that relinquished its ownership interest in the Nold #1S well as a result of a non-consent election in the re-completion of the well has asserted that it did not relinquish its entire interest, but rather became subject only to a 400 percent payout provision. In November 2003, the company filed a lawsuit in the District Court of Brazoria County, Texas, against us for breach of contract. If the suit is successful, it could result in a judgment of as much as $700,000. At this point in time, we cannot predict the outcome of this case.

In December 2003, we filed a lawsuit in the United States District Court for the Western District of Texas against another company and a former employee concerning the defendants' misappropriation of our trade secrets and breach of confidentiality obligations. We are seeking recovery of our damages and injunctive relief. Defendants have denied any wrongdoing and have asserted a counterclaim against us for alleged tortuous interference with an existing business relationship between the company and its employee. The counterclaim does not specify the amount of damages claimed other than that the damages exceed $75,000 (the jurisdictional limit). At this point in time, we cannot predict the outcome of this case.

As of December 31, 2003, there are no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability to us. Compliance with environmental laws and regulations has not had, and is not expected to have, a material adverse effect on our capital expenditures.

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 2003.

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 are our executive officers as of March 26, 2004.

Name	Age	Position
Ben M. Brigham	44	Chief Executive Officer, President and Chairman
Eugene B. Shepherd, Jr.	45	Executive Vice President and Chief Financial Officer
David T. Brigham	43	Executive Vice President — Land and Administration and Director
A. Lance Langford	41	Executive Vice President — Operations
Jeffery E. Larson	45	Executive 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 brother of David T. Brigham, Executive Vice President — Land and Administration.

Eugene B. Shepherd, Jr. has served as Executive Vice President since September 2003 and 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 July 1998 to August 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. from 1990 to June 1998 and with Merrill Lynch Capital Markets from 1986 to 1990. 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 a Director since May 2003, and as Executive Vice President — Land and Administration since June 2002. Mr. Brigham served as Senior Vice President — Land and Administration from March 2001 to June 2002, Vice President — Land and Administration from February 1998 to March 2001, as Vice President — Land and Legal from 1994 until February 1998 and as Corporate Secretary from February 1998 to September 2002. 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, served as Senior Vice President — Operations from March 2001 to September 2003 and has served as Executive Vice President — Operations since September 2003. 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.

Jeffery E. Larson joined us in 1997 and was Vice President — Exploration from August 1999 to March 2001, Senior Vice President — Exploration from March 2001 to September 2003 and has served as Executive Vice President — Exploration since September 2003. 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 from 1990 to 1997 in various roles of responsibility. 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***

Price Range of Common Stock and Dividend Policy

Our common stock commenced trading on the Nasdaq National Market on May 8, 1997 under the symbol "BEXP." The following table sets forth the high and low intra-day sales prices per share of our common stock for the periods indicated on the Nasdaq National Market for the periods indicated. The sales information below reflects inter-dealer prices, without retail mark-ups, mark-downs or commissions and may not necessarily represent actual transactions.

	High	Low
2002:		
First Quarter	3.970	2.360
Second Quarter	5.350	3.420
Third Quarter	4.800	3.100
Fourth Quarter	5.000	3.300
2003:		
First Quarter	6.000	4.400
Second Quarter	5.740	4.500
Third Quarter	7.200	4.750
Fourth Quarter	8.410	6.260

The closing market price of our common stock on March 26, 2004 was $6.78 per share. As of March 26, 2004, there were an estimated 122 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, senior subordinated notes and Series A preferred stock restrict our ability to pay dividends on our common stock.

We are obligated 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 our Series A preferred stock expires in October 2005. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Capital Commitments — Mandatorily Redeemable 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, 2003:

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(a)	2,582,675	$4.78	1,080,296
Equity compensation plans not approved by security holders	—	—	—
Total	2,582,675	$4.78	1,080,296

(a) Does not include 411,171 shares of restricted stock at December 31, 2003.

Recent Issuance of Unregistered Securities

Common Stock

All shares of common stock issued in the following transactions were exempted from registration under section 4(2) of the Securities Act of 1933.

In December 2002, we issued 550,000 unregistered shares of our common stock to Shell Capital. The common stock was issued in exchange for Shell Capital's warrant position, including 1,250,000 warrants associated with our senior subordinated notes facility, and to terminate its right to convert $30 million of our senior credit facility into 5,480,769 shares of our common stock. Shell Capital subsequently sold these shares in our common stock sale in September 2003 and we received no proceeds from the sale of the common stock.

In December 2002, we issued 243,902 unregistered shares of our common stock to a group of institutional investors led by affiliates of two members of our board of directors. The common stock was issued to the group in connection with its cash exercise of warrants to purchase 243,902 shares of our common stock for $2.5625 per share. We received cash proceeds $625,000 from the exercise. The warrants exercised represented a portion of the warrants that were issued in connection with our sale of 731,707 shares of our common stock in February 2000. The remaining warrants were exercised in February 2003.

In February 2003, we issued 248,028 unregistered shares of our common stock to a group of institutional investors led by affiliates of two of our board members. The common stock was issued to the group in connection with its cashless exercise of warrants to purchase 487,805 shares of our common stock for $2.5625 per share. We received no proceeds from the warrant exercise. The warrants exercised represented a portion of the warrants that were issued in connection with our sale of 731,707 shares of our common stock in February 2000.

In June 2003, we issued 408,928 unregistered shares of our common stock to the Bank of Montreal. The common stock was issued to the Bank of Montreal in connection with its cashless exercise of warrants to purchase 661,538 shares of our common stock for $2.02 per share. We received no proceeds from the warrant exercise. The warrants were issued as consideration for an amendment to a previous senior credit facility in July 1999. The original warrant exercise price of $2.25 per share was reset to $2.02 in February 2000 in connection with an amendment to a previous senior credit facility. The Bank of Montreal subsequently sold these shares in our common stock sale in September 2003 and we received no proceeds from the sale of the common stock.

In June 2003, we issued 206,982 unregistered shares of our common stock to Sociète Gènèrale. The common stock was issued to Sociète Gènèrale in connection with its cashless exercise of warrants to purchase 338,462 shares of our common stock for $2.02 per share. We received no proceeds from the warrant exercise. The warrants were issued as consideration for an amendment to a previous senior credit facility in July 1999. The original warrant exercise price of $2.25 per share was reset to $2.02 in February 2000 in connection with an amendment to a previous senior credit facility. Sociète Gènèrale subsequently sold these shares in our common stock sale in September 2003 and we received no proceeds from the sale of the common stock.

In November 2003, we issued 6,666,667 unregistered shares of our common stock to CSFB Private Equity. The common stock was issued to CSFB Private Equity in connection with its exercise of warrants to purchase 6,666,667 shares of our common stock for $3.00 per share. Pursuant to the warrant agreement, we required CSFB Private Equity to exercise the warrants as the average price of our common stock closed above $5.00 per share each day for 60 consecutive days. CSFB Private Equity elected to use 1,000,002 shares of Series A preferred stock to pay the $20 million exercise price. The warrants were issued in connection with our sale of $20 million of Series A — Tranche 1 preferred stock to CSFB Private Equity in November 2000.

In December 2003, we issued 2,105,263 unregistered shares of our common stock to CSFB Private Equity. The common stock was issued to CSFB Private Equity in connection with its exercise of warrants to purchase 2,105,263 shares of our common stock for $4.35 per share. The original exercise price for the warrants was $4.75, but was reset in December 2002, in connection with the issuance of our Series B preferred stock. Pursuant to the warrant agreement, we required CSFB Private Equity to exercise the warrants as our stock price averaged at least $6.525 (150% of the exercise price of the warrants) for 60 consecutive trading days. CSFB Private Equity elected to use 457,898 shares of Series A preferred stock to pay the $9.2 million exercise price and we received no proceeds from the warrant exercise. The warrants were issued in connection with our sale of $10 million of Series A — Tranche 2 preferred stock to CSFB Private Equity in March 2001. See "— Mandatorily Redeemable Preferred Stock."

In December 2003, we issued 2,298,850 unregistered shares of our common stock to CSFB Private Equity. The common stock was issued to CSFB Private Equity in connection with its exercise of warrants to purchase 2,298,850 shares of our common stock for $4.35 per share. Pursuant to the warrant agreement, we required CSFB Private Equity to exercise the warrants as our stock price averaged at least $6.525 (150% of the exercise price of the warrants) for 60 consecutive trading days. CSFB Private Equity elected to use 500,002 shares of Series B preferred stock to pay the $10 million exercise price and we received no proceeds from the warrant exercise. The warrants were issued in connection with our sale of $10 million of Series B preferred stock to CSFB Private Equity in December 2002. See "— Mandatorily Redeemable Preferred Stock."

Mandatorily Redeemable Preferred Stock

All shares of mandatorily redeemable preferred stock issued in the following transactions were exempted from registration under section 4(2) of the Securities Act of 1933.

In March 2001, we issued to CSFB Private Equity 500,000 shares of our Series A — Tranche 2 preferred stock with a stated value of $20.00 per share. Net proceeds from the offering were $9.8 million and were used to fund our exploration and development activities and working capital requirements. The Series A — Tranche 2 preferred stock has terms similar to our previously issued Series A preferred stock. We are required to pay dividends on our Series A preferred stock at a rate of 6% per annum if paid in cash or 8% per annum if paid in kind through the issuance of additional shares of preferred stock in lieu of cash. Our option to pay dividends in kind expires in October 2005. In connection with the issuance of the Series A — Tranche 2 preferred stock, we issued to CSFB Private Equity warrants to purchase 2,105,263 shares of our common stock at an exercise price of $4.75 per share. The original exercise price for the warrants was reset in December 2002, in connection with the issuance of our Series B preferred stock. To exercise the warrants, CSFB Private Equity had the option to use either cash or shares of Series A preferred stock with an aggregate value equal to the exercise price. In December 2003, CSFB Private Equity elected to use 457,898 shares of Series A preferred stock to pay the $9.2 million warrant exercise price. See "— Common Stock."

In December 2002, we issued to 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 previously issued Series A preferred stock. We were required to pay dividends on our Series B preferred stock at a rate of 6% per annum if paid in cash or 8% per annum if paid in kind through the issuance of additional shares of preferred stock in lieu of cash. Our option to pay dividends in kind would have expired in December 2007. In connection with the issuance of the Series B preferred stock, 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 had the option to use either cash or shares of our Series B preferred stock with an aggregate value equal to the exercise price. In December 2003, CSFB Private Equity elected to use 500,002 shares of Series B preferred stock to pay the $10 million warrant exercise price. See "— Common Stock." In addition, pursuant to the terms of the Series B preferred stock we paid CSFB Private Equity approximately $704,000 to redeem the shares of Series B preferred stock that remained outstanding after the exercise.

Item 6. ***Selected Consolidated Financial Data***

This section presents our selected consolidated financial data and 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." The selected consolidated financial data in this section is not intended to replace the consolidated financial statements.

We derived the statement of operations data and statement of cash flows data for the years ended December 31, 2003, 2002 and 2001, and balance sheet data as of December 31, 2003 and 2002 from the audited consolidated financial statements included in this report. We derived the statement of operations data and statement of cash flows data for the years ended December 31, 2000 and 1999 and the balance sheet data as of December 31, 2001, 2000 and 1999 from audited consolidated financial statements that are not included in this report.

	Year Ended December 31,				
	2003	2002	2001	2000	1999
	(Dollars in thousands, except per share information)				
Statement of Operations Data:					
Oil and natural gas sales	$51,545	$35,100	$32,293	$19,143	$ 14,992
Other revenues	132	76	255	69	285
Total revenues	51,677	35,176	32,548	19,212	15,277
Lease operating	5,200	3,759	3,486	2,139	2,259
Production taxes	2,477	1,977	1,511	1,786	968
General and administrative	4,500	4,971	3,638	3,100	3,481
Depletion of oil and natural gas properties	16,972	14,594	13,211	7,920	7,792
Depreciation and amortization	629	440	677	620	526
Accretion of discount on asset retirement obligations	142	—	—	—	—
Loss on sale of oil and natural gas properties	—	—	—	—	12,195
Total costs and expenses	29,920	25,741	22,523	15,565	27,221
Operating income (loss)	21,757	9,435	10,025	3,647	(11,944)
Other income (expense)					
Interest expense, net	(4,815)	(6,238)	(6,681)	(9,906)	(9,697)
Interest income	45	119	264	108	176
Other income (expense)	(601)	(310)	8,080	(9,504)	(163)
Debt conversion expense	—	(630)	—	—	—
Gain on refinancing of debt	—	—	—	32,267	—
Total other income (expense)	(5,371)	(7,059)	1,663	12,965	(9,684)
Income (loss) before income taxes and cumulative effect of change in accounting principle	$16,386	$ 2,376	$11,688	$16,612	$(21,628)
Income tax benefit	1,636	—	—	—	—
Income (loss) before cumulative effect of change in accounting principle	18,022	2,376	11,688	16,612	(21,628)
Cumulative effect of change in accounting principle	268	—	—	—	—
Net income (loss)	18,290	2,376	11,688	16,612	(21,628)
Preferred dividend and accretion	3,448	2,952	2,450	275	—
Net income (loss) available to common stockholders	$14,842	$ (576)	$ 9,238	$16,337	$(21,628)
Net income (loss) per share before cumulative effect of change in accounting principle					
Basic	$ 0.63	$ (0.04)	$ 0.58	$ 1.01	$ (1.53)
Diluted	0.52	(0.04)	0.44	1.01	(1.53)
Weighted avg shares outstanding					
Basic	23,363	16,138	15,988	16,241	14,152
Diluted	34,354	16,138	28,205	16,241	14,152

	At December 31,				
	2003	2002	2001	2000	1999
	(Dollars in thousands)				
Statement of Cash Flows Data:					
Net cash provided (used) by:					
Operating activities	$ 41,691	$ 28,973	$ 18,922	$ (4,635)	$ 2,578
Investing activities	(46,089)	(27,206)	(33,571)	(26,071)	1,644
Financing activities	(5,141)	8,439	18,924	28,801	(4,049)
Balance Sheet Data:					
Cash and cash equivalents	$ 5,779	$ 15,318	$ 5,112	$ 837	$ 2,742
Oil and natural gas properties, net	197,311	164,980	151,891	129,490	112,066
Total assets	224,216	202,059	173,075	146,911	125,683
Long-term debt	39,000	81,797	91,721	82,000	97,341
Series A preferred stock, mandatorily redeemable	8,794	19,540	16,614	8,558	—
Series B preferred stock, mandatorily redeemable	—	4,777	—	—	—
Total stockholders' equity	138,345	61,749	49,601	34,757	8,998

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.

Overview

We are an independent exploration and production company that applies 3-D seismic imaging and other advanced technologies to systematically explore for and develop onshore oil and natural gas reserves in the United States. Our activities are concentrated in the onshore Texas Gulf Coast, the Anadarko Basin and West Texas, which are areas with known hydrocarbon resources, which are conducive to multi-well, repeatable drilling programs and the skills of our technical staff.

Our principal business is the generation of drilling prospects in our core provinces, the drilling of those prospects and, if successful, the subsequent completion and production of the resulting oil or natural gas well. We do not have a history of aggressively competing for acquisition opportunities, although we regularly review such opportunities. We believe that we can achieve a better and more predictable rate of return by focusing our activities on prospect generation, drilling and producing activities.

To support our prospect generation activities, we allocate a portion of our capital expenditures to land, geophysical and geological activities. Over the past three years capital expenditures for land, geophysical and geological activities represented 12% of our total capital expenditures. For 2004, we expect to spend approximately 15% of our total capital expenditures on land, geophysical and geological activities.

The capital that funds our drilling activities is allocated to individual prospects based on the value potential of a prospect, as measured by a risked net present value analysis. We start each year with a budget and reevaluate this budget monthly. The primary factors that impact this value creation measure include forecasted commodity prices, drilling and completion costs, and a prospect's risked reserve size and risked initial producing rate. Other factors that are also monitored throughout the year that influence the amount and timing of our drilling expenditures include the level of production from our existing oil and natural gas properties, the availability of drilling and completion services, and the success and resulting production of our newly drilled wells. The outcome of our monthly analysis results in a reprioritization of our exploration and development well drilling schedule to ensure that we are optimizing our capital expenditure plan.

Over the past three years, we have spent approximately $33 million to drill 48 exploratory wells, which represents 30% of our total capital expenditures for that time period. For 2004, we currently plan to spend approximately $22 million, or 28% of our total budgeted capital expenditures to drill 23 exploratory wells. We believe that we possess a multi-year inventory of exploratory drilling prospects, the majority of which have been internally generated by our staff. As a consequence and considering the results that we have achieved in recent years, we expect that we will continue to emphasize our prospect generation and drilling strategy as our primary means of creating value for our shareholders.

Over the past three years we have spent approximately $49.1 million to drill 45 development wells, which represents 45% of our total capital expenditures for that time period. Due to our exploratory drilling success, over the last four years, a growing percentage of our capital expenditures have been allocated to the development of our six significant field discoveries. We expect this trend to continue, and for 2004 currently plan to spend approximately $39.4 million, or 50% of our total budgeted capital expenditures to drill 36 development wells.

2003 Highlights

During 2003, we achieved several financial and operational milestones. The following are some of the highlights for 2003.

- Our average daily production for 2003 was 29.7 MMcfe/d and increased 7% over average daily production in 2002.
- We added approximately 23.8 Bcfe of proved reserves, of which 20 Bcfe were proved developed, growing our estimated net proved reserve volumes by 11% and replacing 223% of our 2003 production.
- We made a new field discovery at Floyd South.
- We expanded our Diablo Project area with two new joint ventures.
- We acquired two new 3-D seismic data sets in the Gulf Coast, which have already generated four discoveries in four attempts.
- We reported operating income of $21.8 million, up 131% when compared to operating income for 2002.
- Our earnings for 2003 were $0.53 per diluted share relative to a net loss of $0.04 in 2002.
- Our common stock offering in September 2003, combined with the exercise of the Series A and Series B warrants and our earnings, improved our balance sheet and strengthened our overall financial position by reducing our total debt to capitalization ratio from 63% at December 31, 2002 to 27% at December 31, 2003.
- In November 2003, we significantly increased our drilling expenditures. We plan to use the availability under our senior credit facility, along with our internally generated cash flow and cash on hand, to accelerate our drilling activities in the current environment of high commodity prices and relatively low service costs.

2004 Outlook

Our total net capital spending budget for 2004 is $79 million. The majority of our planned 2004 expenditures will be directed toward the drilling of our exploration and development inventory to focus resources on our primary objective of growing our reserves, production volumes and cash flow. For 2004, we expect to drill 59 (36 development and 23 exploratory) wells with an average working interest of approximately 42%. Capitalizing on our prior discoveries, including the Home Run, Mills Ranch, Triple Crown, Floyd Fault Block, Floyd South Fault Block and Providence Fields, approximately 64% of our 2004 drilling expenditures are allocated to development drilling. Our current cash balance, cash flow from operations and availability under our senior credit facility, will fund our spending. Estimated net capital expenditures for 2004 represent an increase of approximately 61% over the amount that we spent in 2003. The final determination with respect to our 2004 budgeted expenditures will depend on a number of factors, including:

- commodity prices;
- production from our existing producing wells;
- the results of our current exploration and development drilling efforts;
- economic and industry conditions at the time of drilling, including the availability of drilling equipment; and
- the availability of more economically attractive prospects.

There can be no assurance that the budgeted wells will, if drilled, encounter commercial quantities of natural gas or oil.

Statements in this section include forward-looking statements. See "— Forward-Looking Statements."

Critical Accounting Policies

The establishment and consistent application of accounting policies is a vital component of accurately and fairly presenting our consolidated financial statements in accordance with generally accepted accounting principles (GAAP), as well as ensuring compliance with applicable laws and regulations governing financial reporting. While there are rarely alternative methods or rules from which to select in establishing accounting and financial reporting policies, proper application often involves significant judgment regarding a given set of facts and circumstances and a complex series of decisions.

Property and Equipment

The method of accounting for oil and natural 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 natural gas properties. Under this method substantially all costs associated with oil and natural 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. A portion of the 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 unamortized historical and estimated future development costs to proven hydrocarbon reserve volumes. Estimation of hydrocarbon reserves relies on professional judgment and use of factors that cannot be precisely determined. Subsequent reserve estimates materially different from those reported would change the depletion expense recognized during the future reporting period. For the year ended December 31, 2003, our depletion expense per unit of production was $1.59 per Mcfe. A change of 900,000 Mcfe in our estimated net proved reserves at December 31, 2003, would result in a $0.01 per Mcfe change in our per unit depletion expense and a $107,000 change in our pre-tax net income.

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 hedge adjusted oil and natural gas prices) of estimated future net cash flows 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 natural gas properties increases when oil and natural 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 That May Not Result In Commercially Productive Reserves And May Require Expenditures In Excess Of Budgeted Amounts," "— Risk Factors — The Failure To Replace Reserves In The Future Would Adversely Affect Our Production And Cash Flows" and "— Risk Factors — We Are Subject To Uncertainties In Reserve Estimates And Future Net Cash Flows."

Asset Retirement Obligations

We have significant obligations to plug and abandon oil and natural gas wells and related equipment. Liabilities for asset retirement obligations are recorded at fair value in the period incurred. The related asset value is increased by the same amount. Asset retirement costs included in the carrying amount of the related asset are subsequently allocated to expense as part of our depletion calculation. See "— Property and Equipment." Additionally, increases in the discounted asset retirement liability resulting from the passage of time are reflected as accretion of discount on asset retirement obligations expense in the Consolidated Statement of Income.

Estimating future asset retirement obligations requires us to make estimates and judgments regarding timing, existence of a liability, as well as what constitutes adequate restoration. We use the present value of estimated cash flows related to our asset retirement obligations to determine the fair value. Present value calculations inherently incorporate numerous assumptions and judgments. These include the ultimate retirement and restoration costs, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation liability, a corresponding adjustment will be made to the carrying cost of the related asset.

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 stockholder ownership that would trigger limits on use of net operating losses under Internal Revenue Code Section 382.

We have a significant deferred tax asset associated with net operating loss carryforwards (NOLs). It is more likely than not that we could begin using these NOLs to offset current tax liabilities during 2004. Our NOLs are more fully described in "Notes to the Consolidated Financial Statements — Note 9."

Revenue Recognition

We derive revenue primarily from the sale of produced oil and natural gas, hence our revenue recognition policy for these sales is significant.

We recognize crude oil revenue using the sales method of accounting. Under this method, revenue is recognized 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 delivered 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.

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 similarly use derivative instruments to manage risks associated with interest rate fluctuations on long term debt. During 2003 we entered into an interest rate swap to convert the floating interest rate on our senior subordinated notes to a fixed interest rate to reduce our exposure to potentially higher interest rates in the future. The notional amount of this hedge is equal to the amount of senior subordinated notes outstanding, and is more fully described in "Notes to the Consolidated Financial Statements — Note 5" and "Notes to the Consolidated Financial Statements — Note 12."

We adopted Statement of Financial Accounting Standards No. 133 (SFAS 133) on January 1, 2001 in accordance with Financial Accounting Standards Board (FASB) requirements. SFAS 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 are cash flow hedge transactions in which we are hedging the variability of cash flow related to a forecasted transaction. Changes 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 the fair value of the ineffective portion of 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 reserves, future development costs, and certain hydrocarbon production expense and revenue estimates are the most critical to our financial statements.

New Accounting Pronouncements

In May 2003, the FASB issued Statement of Financial Accounting Standards No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity" (SFAS 150). SFAS 150 requires us to classify certain financial instruments, such as mandatorily redeemable preferred stock, as liabilities (or assets in some circumstances). We adopted this standard as required on July 1, 2003. Upon adoption, approximately $8 million of mandatorily redeemable Series A and B preferred stock was reclassified to long-term debt. Dividends of approximately $340,000 on the reclassified amount of mandatorily redeemable Series A and B preferred stock are included in our Consolidated Statement of Operations as interest expense.

Commodity Prices

Changes in commodity prices significantly affect our capital resources, liquidity and operating results. Price changes directly affect revenues and can indirectly impact expected production by changing the amount of available capital to reinvest in our exploration and development activities. Commodity prices are impacted by many factors that are outside of our control. Over the past couple of years, commodity prices have been very volatile. We expect that commodity prices will continue to fluctuate significantly in the future. As a result, we cannot accurately predict future oil and natural gas prices, and therefore, we cannot determine what effect increases or decreases will have on our capital program, production volumes and future revenues.

The prices we receive for our crude oil production are based on global market conditions. During 2003, oil prices increased in response to political unrest and supply disruptions in the Middle East as well as other supply and demand factors. Our average sales price for oil in 2003 was $30.79 per barrel, which was 22% higher than the price we received in 2002. Significant factors that will impact 2004 oil prices include developments in Iraq and other Middle East countries, the extent to which members of the Organization of Petroleum Exporting Countries and other oil exporting nations are able to manage oil supply through export quotas. North American market forces primarily drive the price we receive for our natural gas production. Factors that can affect the price of natural gas are changes in market demands, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. Over the past two years natural gas prices have been volatile. The average sales price that we received for natural gas in 2003 was $5.68 per Mcf, which was 71% higher than the sales price that we received for sales in 2002. The average sales price that we received for natural gas in 2002 was $3.33 per Mcf, which was 22% lower than the sales price that we received in 2001. The increase North American gas prices in 2003 were in response to strong supply and demand fundamentals. Natural gas prices for 2004 will depend on variations in key North American gas supply and demand indicators.

Capital Commitments

Our primary needs for cash are for the exploration and development of oil and gas properties, repayment of contractual obligations and funding working capital obligations. Funding for the exploration and development of oil and gas properties and repayment of contractual obligations may be provided by any combination of cash flow from operations, cash on our balance sheet, the unused committed borrowing capacity under our senior credit facility, reimbursements of prior land and seismic costs by participants in our projects and the sale of interests in projects and properties or alternative financing sources as discussed in "— Capital Resources and Liquidity." Funding for our working capital obligations is provided by cash flows from operations and the unused committed borrowing capacity under our senior credit facility.

Contractual Obligations

The following schedule summarizes our known contractual cash obligations at December 31, 2003 and the effect such obligations are expected to have on our liquidity and cash flow in future periods.

	Payments Due by Year				
	Total Outstanding	2004	2005	2006-2007	2008 and Thereafter
	(Dollars in thousands)				
Senior credit facility(a)	$19,000	$ —	$ —	$19,000	$ —
Senior subordinated notes(b)	20,000	—	—	—	20,000
Mandatorily redeemable, Series A preferred stock(c)	8,794	—	—	—	8,794
Non-cancelable operating leases(d)	3,185	910	910	1,365	—
Total contractual cash obligations	$50,979	$910	$910	$20,365	$28,794

(a) Based on $19 million outstanding and an interest rate at December 31, 2003, of 2.7%, we would be required to pay $513,000 in interest per year until our senior credit facility matures. This amount of interest will fluctuate over time as borrowings under our senior credit facility increase or decrease and as the applicable interest rate increases or decreases. See "Item 7A Quantitative and Qualitative Disclosures About Market Risk — Quantitative Disclosures — Interest Rate Risk."

(b) Based on $20 million outstanding and a current interest rate of 8.8%, we would be required to pay $1.8 million in interest per year until our senior subordinated notes mature.

(c) At our option, dividends on our Series A preferred stock 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 expires in November 2005. If we elect to pay the dividends in cash, based on $8.8 million outstanding we would be required to pay $528,000 in dividends per year until our mandatorily redeemable Series A preferred stock matures. If we elect to pay the dividends in kind, in 2004 we would be required issue approximately 36,250 shares of additional Series A preferred to pay dividends of $725,000. In 2005, we would be required to issue approximately 32,483 shares of additional Series A preferred stock to pay dividends of $649,660. The dividends in 2005 represents dividends on the outstanding Series A preferred stock from January 1, 2005 to October 31, 2005, the expiration of our option to pay dividends in kind. Thereafter, we would be required to pay an annual cash dividend of approximately $610,000 until maturity.

(d) Not reduced by rental payments that we will receive from a non-cancelable sublease of approximately $64,000 due in 2004 and $38,000 due in 2005.

Senior Credit Facility

As of December 31, 2003, we had $19 million in borrowings outstanding under our senior credit facility. In March 2003, we replaced our then existing senior credit facility with a new senior credit facility that provides for a maximum $80 million in commitments and an initial committed borrowing base of $70 million and matures in March 2006.

The collateral value and borrowing base are redetermined semi-annually and are based in part on prevailing oil and natural gas prices. If, upon redetermination, our borrowing base decreases, we may have to repay a portion of our borrowings within 90 days, our access to further borrowings will be reduced, and we may not have the resources necessary to carry out our planned drilling activities. Based on the most recent determination effective December 1, 2003, the committed borrowing base was set at $68.5 million. The unused portion of the committed borrowing base is subject to an annual commitment fee of 0.5%. See "— Liquidity and Capital Resources — Common Stock Transactions" and "— Liquidity and Capital Resources — Senior Credit Facility" for explanation of the changes in our outstanding debt balance under our senior credit facility.

As of March 26, 2004, we had $29.2 million of borrowings outstanding and $39.3 million of additional borrowing capacity under our senior credit facility.

Borrowings under our senior credit facility are secured by substantially all of our oil and natural gas properties. At our option, borrowings under our senior credit facility bear interest at a rate equal to: (i) the base rate of Société Générale plus a margin which fluctuates from 0.5% to 1.5% depending on facility usage or (ii) LIBOR for one, two, three or six months plus a margin which fluctuates from 1.5% to 2.5% depending on facility usage. Interest is due quarterly for base rate tranches or periodically as LIBOR tranches mature.

The 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. Our 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. Our current ratio at December 31, 2003 and interest coverage ratio for the twelve-month period ending December 31, 2003, were 2.0 to 1 and 8.2 to 1, respectively.

Senior Subordinated Notes

As of December 31, 2003, we had $20 million of senior subordinated notes outstanding. The terms of the senior subordinated notes were amended in March 2003 in order to have the covenants and other features of the notes mirror those of the new senior credit facility put in place at the same time. See "— Senior Credit Facility." The terms of the senior subordinated notes were amended again in December 2003 to reduce the outstanding balance of the notes to $20 million, reduce the interest rate and extend the maturity of the notes from October 2005 until March 2009. Prior to the December 2003 amendment, the senior subordinated notes bore interest at 10.75% per annum, were redeemable at our option for face value at any time and had no principal repayment obligations. As a consequence of the December 2003 amendment, the 10.75% fixed rate coupon was converted to a floating rate coupon. Simultaneous with the completion of the amendment, we entered into an interest rate swap contract to fix the coupon at 8.76% through the new maturity date. Interest on the senior subordinated notes is payable quarterly in arrears on the first business day following the last day of each quarter ended March, June, September and December. See "— Liquidity and Capital Resources — Senior Subordinated Notes" for explanation of the changes in our outstanding senior subordinated notes balance.

The senior subordinated notes are secured obligations ranking junior to our senior credit facility and have covenants similar to the senior credit facility. As part of the December 2003 amendment, one additional covenant was added. We are required to maintain a ratio of risked net present value (as defined) discounted at 9% to total debt of 1.5 to 1.

Mandatorily Redeemable Preferred Stock

As of December 31, 2003, we had $8.8 million in mandatorily redeemable Series A preferred stock outstanding, which is held by merchant banking funds managed by affiliates of CSFB Private Equity. At our option, the dividends on our Series A preferred stock 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 expires in October 2005. 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 matures in November 2010 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.

Our preferred stock balance outstanding at December 31, 2003, represents the balance of preferred stock that remained outstanding after CSFB Private Equity exercised its warrants to purchase our common stock in November and December of this year. Over the past four years we have issued mandatorily redeemable preferred stock to CSFB Private Equity on three different occasions. The first issuance was in November 2000 ($20 million Series A — Tranche 1), the second issuance was in March 2001 ($10 million Series A — Tranche 2) and the third issuance was in December 2002 ($10 million Series B).

In connection with each issuance of mandatorily redeemable preferred stock, we issued to CSFB Private Equity warrants to purchase shares of our common stock. To exercise the warrants, CSFB Private Equity had the option to use either cash or shares of our mandatorily redeemable preferred stock with an aggregate value equal to the exercise price. In November 2000, in connection with the Series A — Tranche 1 we issued CSFB Private Equity warrants to purchase 6,666,667 shares of our common stock at an exercise price of $3.00. In March 2001, in connection with the Series A — Tranche 2 we issued CSFB Private Equity warrants to purchase 2,105,263 shares of our common stock at an exercise price of $4.75. The exercise price on the warrants issued in March 2001 was later reset to $4.35 in connection with the issuance of the December 2002 Series B preferred stock and warrant offering. In December 2002, in connection with the Series B we issued CSFB Private Equity warrants to purchase 2,298,850 shares of our common stock at an exercise price of $4.35 per share. As part of each warrant agreement, we had the option to require CSFB Private Equity to exercise the warrants if the price of our common stock met certain thresholds over a certain period of time. In the event our stock price closed above $5.00 per share each day for 60 consecutive days, we could require CSFB Private Equity to exercise the warrants to purchase 6,666,667 shares of our common stock at an exercise price of $3.00. If our stock price averaged at least $6.525 (150% of the exercise price of the warrants) over 60 consecutive trading days, then we could require CSFB Private Equity to exercise the warrants to purchase 2,105,263 shares of our common stock at an exercise price of $4.35 and the warrants to purchase 2,298,850 shares of our common stock at an exercise price of $4.35.

In November 2003, our stock price met the threshold, which enabled us to require CSFB Private Equity to exercise the warrants to purchase 6,666,667 shares of our common stock at an exercise price of $3.00. In November 2003, our average stock price met the threshold, which enabled us to require CSFB Private Equity to exercise the warrants to purchase 2,105,263 shares of our common stock at an exercise price of $4.35 and the warrants to purchase 2,298,850 shares of our common stock at an exercise price of $4.35. In all three cases, we required CSFB Private Equity to exercise the warrants. The combined exercise price of the warrants was $39.2 million and CSFB Private Equity elected to use 1,457,900 shares of Series A preferred stock and 500,002 shares of Series B preferred stock to pay for the exercise of the warrants. In addition, pursuant to the terms of the Series B preferred stock we paid CSFB Private Equity approximately $704,000 to redeem the shares of Series B preferred stock that remained outstanding after the exercise.

Our outstanding balance of mandatorily redeemable preferred stock at December 31, 2003, consisted of the Series A shares that remained outstanding after the exercise and an additional 24,738 Series A shares issued to satisfy pay in kind dividends for the fourth quarter of 2003.

Capital Expenditures

The timing of most of our capital expenditures is discretionary because we have no material long-term capital expenditure commitments. Consequently, we have a significant degree of flexibility to adjust the level of our capital expenditures as circumstances warrant. Our capital expenditures for the past three years are as follows:

	Year Ended December 31,		
	2003	2002	2001
	(Dollars in thousands)		
Drilling	$35,106	$19,800	$27,209
Land, geological and geophysical	6,867	3,751	2,750
Capitalized general and administrative expenses and interest	6,081	5,657	6,050
Proceeds from participants and sales	(1,220)	(1,524)	(397)
Net capital expenditures on oil and gas activities	$46,834	27,684	35,612
Other property and equipment	349	249	241
Total net capital expenditures	$47,183	$27,933	$35,853
Amounts spent to develop our proved undeveloped reserves	$11,399	$ 9,983	$ 8,175

Off Balance Sheet Arrangements

We currently have operating leases, which are considered off balance sheet arrangements. See "— Contractual Obligations" for future obligations associated with our operating leases. We do not currently have any other off balance sheet arrangements or other such unrecorded obligations, and we have not guaranteed the debt of any other party.

Results of Operations

Comparison of the twelve-month periods ended December 31, 2003, 2002 and 2001

Production. Our net equivalent production volumes for 2003 were 10.7 Bcfe (29.7 MMcfe/d) compared to 10.0 Bcfe (27.8 MMcfe/d) in 2002 and 9.6 Bcfe (26.6 MMcfe/d) in 2001. The increase in production volume was due to production growth from wells that were drilled and completed during the periods. New production from these wells was partially offset by the natural decline of existing production. Natural gas represented 60%, 58% and 71% of our total production in 2003, 2002 and 2001, respectively.

	Year Ended December 31,				
	2003	% Change	2002	% Change	2001
Net Production Volumes:					
Natural gas (MMcf)	6,356	10%	5,791	(14)%	6,766
Oil (MBbls)	720	3%	701	50%	468
Natural gas equivalent (MMcfe)	10,674	7%	9,996	4%	9,573

For 2003 compared to 2002, the change in our production volumes was due to the following:

- Production from our Gulf Coast province for 2003 increased 24% when compared to production from that province in 2002. Gulf Coast production represented 61% of our total production in 2003 versus 53% in 2002. Natural gas represented approximately 60% of the total production from the Gulf Coast in 2003 compared to 61% in 2002.
- Production from our Anadarko Basin province for 2003 decreased 6% when compared to production from that province in 2002. Anadarko Basin production represented 23% of our total production in 2003 versus 26% in 2002. Natural gas represented approximately 90% of the total production from the Anadarko Basin in 2003 and 2002.
- Production from our West Texas province for 2003 decreased 21% when compared to production from that province in 2002. West Texas production represented 16% of our total production versus 21% in 2002. Production from our West Texas province is primarily oil. Oil represented approximately 85% of the total production from our West Texas province in 2003 versus 88% in 2002.

For 2002 compared to 2001, the change in our production volumes was due to the following:

- Production from our Gulf Coast province for 2002 increased 37% when compared to production from that province in 2001. Gulf Coast production represented 53% of our total production in 2002 versus 41% in 2001. Natural gas represented approximately 61% of the total production from the Gulf Coast in 2002 compared to 83% in 2001.
- Production from our Anadarko Basin province for 2002 decreased 30% when compared to production from that province in 2001. Anadarko Basin production represented 26% of our total production in 2002 versus 38% in 2001. Natural gas represented approximately 90% of the total production from the Anadarko Basin in 2002 versus 91% in 2002.
- Production from our West Texas province for 2002 decreased 3% when compared to production from that province in 2001. West Texas production represented 21% of our total production in 2002 and 2001. Production from our West Texas province is primarily oil. Oil represented approximately 88% of the total production from our West Texas province in 2002 and 2001.

Revenue from the sale of oil and natural gas. Revenues from the sale of oil and natural gas that we report are based on the market price received for our commodities adjusted by marketing charges and the results from the settlement of our derivative commodity contracts that qualify for hedge accounting treatment under SFAS 133.

We utilize commodity swap, collar and floor contracts to (i) reduce the effect of price volatility on the commodities that we produce and sell, (ii) reduce commodity price risk and (iii) provide a base level of cash flow in order to assure we can execute at least a portion of our capital spending plans. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk — Qualitative Disclosures — Commodity Price Risk" for a description of derivative commodity contracts.

The effective portions of changes in the fair values of our derivative commodity contracts that qualify for hedge accounting treatment under SFAS 133 are deferred as increases or decreases to stockholders' equity until the underlying contract is settled. Consequentially, changes in the effective portions of our derivative commodity contracts that qualify for hedge accounting treatment under SFAS 133 add volatility to our reported stockholders' equity until the contract is settled or is terminated. See "Notes to the Consolidated Financial Statements — Note 2."

The gain or loss related to the ineffective portion of changes in the fair market value of our derivative commodity contracts that qualify for hedge accounting treatment under SFAS 133 is recognized in other income (expense).

The gain or loss related to the settlement and changes in the fair values of our derivative commodity contracts that do not qualify for hedge accounting treatment under SFAS 133 are recognized in other income (expense).

All of our open derivative commodity contracts at December 31, 2003, qualified for hedge accounting treatment under SFAS 133. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk — Qualitative Disclosures — Commodity Price Risk" for our open derivative commodity contracts at December 31, 2003.

The table below shows revenue that we have realized from the sale of oil and natural gas over the past three years.

	Year Ended December 31,				
	2003	% Change	2002	% Change	2001
	(Dollars in thousands, except per unit measurements)				
Revenue from the sale of oil and natural gas:					
Oil sales	$22,157	26%	$17,644	55%	$11,405
Gain/(loss) due to hedging	(1,885)	66%	(1,135)	642%	(153)
Total revenue from the sale of oil	$20,272	23%	$16,509	47%	$11,252
Natural gas sales	$36,080	87%	$19,303	(34)%	$29,042
Gain/(loss) due to hedging	(4,807)	575%	(712)	(91)%	(8,001)
Total revenue from the sale of natural gas	$31,273	68%	$18,591	(12)%	$21,041
Oil and natural gas sales	$58,237	58%	$36,947	(9)%	$40,447
Gain/(loss) due to hedging	(6,692)	262%	(1,847)	(77)%	(8,154)
Total revenue from the sale of oil and natural gas	$51,545	47%	$35,100	9%	$32,293

	Year Ended December 31,				
	2003	% Change	2002	% Change	2001
	(Dollars in thousands, except per unit measurements)				
Average prices:					
Oil ($ per Bbl)					
Oil	$ 30.79	22%	$ 25.17	3%	$ 24.38
Gain/(loss) due to hedging	(2.62)	62%	(1.62)	391%	(0.33)
Oil realized price	$ 28.17	20%	$ 23.55	(2)%	$ 24.05
Natural gas ($ per Mcf)					
Natural gas sales price	$ 5.68	71%	$ 3.33	(22)%	$ 4.29
Gain/(loss) due to hedging	(0.76)	533%	(0.12)	(90)%	(1.18)
Natural gas realized price	$ 4.92	53%	$ 3.21	3%	$ 3.11
Natural gas equivalent ($ per Mcfe)					
Natural gas equivalent sale price	$ 5.46	48%	$ 3.70	(13)%	$ 4.23
Gain/(loss) due to hedging	(0.63)	232%	(0.19)	(78)%	(0.86)
Natural gas equivalent realized price	$ 4.83	38%	$ 3.51	4%	$ 3.37

Our total revenue from the sale of oil and natural gas in 2003 was 47% higher than total revenue from the sale of oil and natural gas in 2002. The change in our total revenue from the sale of oil and natural gas from 2002 to 2003 is due to the following:

- Approximately $19 million of the increase in oil and natural gas sales was due to a $1.76 Mcfe increase in the sales price that we received for oil and natural gas.

- The remaining $2.3 million of the increase in oil and natural gas sales was due to an increase in our production volumes.

- The increases in total revenue from the sale of oil and natural gas due to higher prices and increased production volumes were partially offset by a 262% increase in losses due to the cash settlement of derivative commodity contracts.

Our total revenue from the sale of oil and natural gas in 2002 was 9% lower than total revenue from the sale of oil and natural gas in 2001. The change in our total revenue from the sale of oil and natural gas from 2002 to 2001 is due to the following:

- Approximately $5 million of the decrease in oil and natural gas sales was due to a $0.53 per Mcfe decline in the average sales price that we received for oil and natural gas.

- The decrease in oil and natural gas sales due to a decline in the average sales price that we received for oil and natural gas was partially offset by a $1.5 million increase in oil and natural gas sales related to an increase in oil and natural gas production.

- The decrease in total revenue from oil and natural gas sales due to a decline in the average sales price that we received for oil and natural gas was partially offset by a 77% decrease in losses due to the cash settlement of derivative commodity contracts.

The following table shows the type of derivative commodity contracts, the volumes, the weighted average NYMEX reference price for those volumes, and the associated gain / (loss) upon settlement of those hedges for 2003, 2002 and 2001.

	Year Ended December 31,		
	2003	2002	2001
Oil swaps			
Volumes (Bbls)	225,525	126,500	—
Average price ($ per Bbl)	$ 24.51	$ 25.96	$ —
Gain/(loss) (dollars in thousands)	$ (1,488)	$ (284)	$ —
Oil collars			
Volumes (Bbls)	45,250	204,500	109,200
Average floor price ($ per Bbl)	$ 18.00	$ 18.00	$ 17.36
Average ceiling price ($ per Bbl)	$ 22.56	$ 22.36	$ 26.15
Gain/(loss) (dollars in thousands)	$ (397)	$ (851)	$ (153)
Natural gas swaps			
Volumes (MMbtu)	2,663,500	3,358,500	1,800,000
Average price ($ per MMbtu)	$ 3.81	$ 3.13	$ 2.09
Gain/(loss) (dollars in thousands)	$ (4,807)	$ (712)	$ (8,006)
Natural gas floors			
Volumes (MMbtu)	1,070,000	—	765,000
Average floor price ($ per MMbtu)	$ 4.50	$ —	$ 1.80
Gain/(loss) (dollars in thousands)	$ —	$ —	$ 5

Other revenue. Other revenue relates to fees that we charge other parties who use our two gas gathering systems to move their production from the wellhead to third party gas pipeline systems. These gathering systems are owned by us and located in the Texas Gulf Coast. One of the gathering systems connects to a single well and the other connects two wells. Other revenue for 2003 was $132,000 compared to $76,000 in 2002 and $255,000 in 2001.

Production costs. Production costs include lease operating expenses and production taxes.

	Year Ended December 31,				
	2003	% Change	2002	% Change	2001
	(Dollars in thousands, except per unit measurements)				
Production cost:					
Lease operating expenses, excluding ad valorem taxes	$4,543	44%	$3,148	4%	$3,015
Ad valorem taxes	657	8%	611	30%	471
Total lease operating expenses	$5,200	38%	$3,759	8%	$3,486
Production taxes	2,477	25%	1,977	31%	1,511
Total production expenses	$7,677	34%	$5,736	15%	$4,997
Production cost ($ per Mcfe):					
Lease operating expenses, excluding ad valorem taxes	$ 0.43	34%	$ 0.32	0%	$ 0.32
Ad valorem taxes	0.06	0%	0.06	20%	0.05
Total lease operating expenses	$ 0.49	29%	$ 0.38	3%	$ 0.37
Production taxes	0.23	15%	0.20	25%	0.16
Total production expenses	$ 0.72	24%	$ 0.58	9%	$ 0.53

Lease operating expenses:

Lease operating expenses are generally comprised of several components which include the cost of labor and supervision to operate the wells and related equipment; repairs and maintenance; related materials, supplies, fuel, and supplies utilized in operating the wells and related equipment and facilities; insurance applicable to wells and related facilities and equipment, workover cost and ad valorem taxes. Lease operating expenses are driven in part by the type of commodity produced, the level of workover activity and the geographical location of the properties. Oil is inherently more expensive to produce than natural gas.

Local taxing authorities such as school districts, cities, and counties or boroughs generally impose the ad valorem taxes we pay. The amount of the tax is based on the value of the property assessed or determined by the taxing authority on an annual basis, and a percent of value. When oil and natural gas commodity prices rise, the value of our underlying property interests increase. This results in higher ad valorem taxes.

For 2003 compared to 2002, approximately 58% of the increase in total lease operating expenses was due to an increase in workover activity, while 39% of the increase was related to an increase in operating and maintenance expense and 3% was related to an increase in ad valorem taxes.

On a per unit basis, our lease operating expenses for 2003 were $0.49 per Mcfe compared to $0.38 in 2002. The $0.11 increase in lease operating expense was primarily due to the following:

- An increase in workover activity represented $0.07 of the increase in lease operating expenses, with two workovers performed on two wells accounting for 100% of this increase.
- The remaining $0.04 of the increase in lease operating expenses was due to increases in overhead fees, insurance, compressor rental and maintenance, saltwater disposal cost, cost for electricity, fuel and power and miscellaneous lease operating expenses. These increases were partly offset by decreases in contract service and labor expenses, lease and well abandonment expenses, lease maintenance expenses and surface equipment repair expenses.

For 2002 compared to 2001, approximately 51% of the increase in total lease operating expenses was due to an increase in ad valorem taxes and 49% of the increase was due to an increase in workover activity, which was partially offset by a decrease in operating and maintenance expenses. The increase in ad valorem taxes was due to an increase in 2002 property valuation because of higher average commodity prices during 2001.

On a per unit basis, our lease operating expenses for 2002 were $0.38 per Mcfe compared to $0.37 in 2001.

- An increase in expenses related to workover activity resulted in a $0.02 increase in lease operating expenses.
- An increase in ad valorem taxes resulted in a $0.01 increase in lease operating expenses.
- These increases were offset by decreases in well service and repair expenses.

Production taxes:

In the U.S. there are a variety of state and federal taxes levied on the production of oil and natural gas. These are commonly grouped together and referred to as production taxes. The majority of our production tax expense is based on a percent of gross value at the well at the time the production is sold or removed from the lease. As a result, our production tax expense increases with increases in crude oil and natural gas commodity prices.

Historically, taxing authorities have occasionally encouraged oil and gas industry to explore for new oil and natural gas reserves, or develop high cost reserves through reduced tax rates or credits. These incentives have been narrow in scope and short-lived. A small number of our wells currently qualify for reduced production taxes because they are discoveries based on the use of 3-D seismic or high cost wells.

For 2003 compared to 2002, the increase in production taxes was due to an increase in the sales prices that we received for both oil and natural gas. The increase in production taxes was offset by a credit related to the settlement of a portion of our gas imbalance. Our effective production tax rate in 2003 was 4.3% of pre-hedge oil and natural gas sales revenue, compared to 5.4% in 2002.

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.

General and administrative expenses. We capitalize a portion of our general and administrative costs. The costs capitalized represent the cost of technical employees, who work directly on capital projects. An engineer designing a well is an example of a technical employee working on a capital project. The cost of a technical employee includes associated technical organization costs such as supervision, telephone and postage.

	Year Ended December 31,				
	2003	% Change	2002	% Change	2001
	(Dollars in thousands, except per unit measurements)				
General and administrative expenses	$4,500	(9)%	$4,971	37%	$3,638
General and administrative expenses ($ per Mcfe)	$ 0.42	(16)%	$ 0.50	32%	$ 0.38

For 2003 compared to 2002, our general and administrative expenses decreased by $471,000. General and administrative expenses for 2002 included a non-cash charge for compensation expense of $596,000 related to vesting of options by an officer who left the company. Excluding this non-cash charge, our general and administrative expenses for 2003 increased by $125,000. The changes in general and administrative expenses for 2003 were primarily due to the following:

- An increase in payroll and employee benefit expenses represented 55% of the total increase in general and administrative expenses. The increase in payroll and benefit expenses was primarily related to an increase incentive compensation expense, an increase in employee medical and life insurance cost and increases in salaries and wages.

- An increase in director fees and financial reporting expenses represented 42% of the total increase in general and administrative expenses. These increases were primarily related to additional cost associated with the implementation of compliance with the Sarbanes-Oxley Act of 2002.

- The increase in payroll and employee benefit expenses was partially offset by an increase in amounts charged to joint ventures to cover the costs of managing these joint operations.

On a per unit basis, our general and administrative expenses for 2003 were $0.42 per Mcfe compared to $0.50 in 2002. A charge for non-cash compensation expense accounted for $0.06 of our 2002 general and administrative expense.

For 2002 compared to 2001, our general and administrative expenses increased by $1.3 million. The changes in general and administrative expenses for 2002 were primarily due to the following:

- A charge for non-cash compensation expense of $596,000 related to vesting of options by an officer who left the company accounted for 45% of the total increase in general and administrative expenses.

- Increases in payroll and benefit expenses represented approximately 20% of the total increase in general and administrative expenses. The increase in payroll and benefit expenses was due to an increase in relocation bonuses, an increase in the cost of employee medical and life insurance and increased salaries.

- An increase in other office expenses accounted for 12% of the increase, an increase in office rent accounted for 6% of the increase and an increase in corporate insurance accounted for approximately 4% of the increase.

Our general and administrative expenses on a per unit basis for 2002 were $0.50 per Mcfe compared to $0.38 during 2001. The charge for non-cash compensation expense accounted for $0.06 of our per unit general and administrative expense in 2002.

Depletion of oil and natural gas properties. Our full-cost depletion expense is driven by many factors including certain costs spent in the exploration and development of producing reserves, production levels, and estimates of proved reserve quantities and future developmental costs at the end of the year.

	Year Ended December 31,				
	2003	% Change	2002	% Change	2001
	(Dollars in thousands, except per unit measurements)				
Depletion of oil and natural gas properties	$16,972	16%	$14,594	10%	$13,211
Depletion of oil and natural gas properties per Mcfe	$ 1.59	9%	$ 1.46	3%	$ 1.38

For 2003 compared to 2002, a $0.13 increase in our depletion rate accounted for approximately $1.4 million of the increase in our total depletion expense and increased production volumes accounted for approximately $1 million of the increase. The increase in our depletion rate was due to an increase in our oil and natural gas finding and development costs incurred in 2003 and an increase in future development costs associated with our year-end 2003 reserves.

For 2002 compared to 2001, a $0.08 increase in our depletion rate accounted for $800,000 of the change in our total depletion expense and higher production volumes accounted for $584,000 of the change. This increase in depletion rate was due to an increase in the future development costs associated with our Floyd Fault Block Field discovery.

Net interest expense. We capitalize interest expense on borrowings associated with major capital projects prior to their completion. Capitalized interest is added to the cost of the underlying assets and is amortized over the lives of the assets.

	Year Ended December 31,				
	2003	% Change	2002	% Change	2001
	(Dollars in thousands)				
Interest on senior credit facility	$ 1,674	(54)%	$ 3,636	(33)%	$ 5,400
Interest on senior subordinated notes(a)	2,369	6%	2,243	33%	1,681
Commitment fees	147	4,800%	3	(90)%	29
Dividend on mandatorily redeemable preferred stock	340	0%	—	0%	—
Amortization of deferred loan and debt issuance cost	1,053	(11)%	1,190	(13)%	1,372
Other general interest expense	50	14%	44	(6)%	47
Capitalized interest expense	(818)	(7)%	(878)	(52)%	(1,848)
Net interest expense	$ 4,815	(23)%	$ 6,238	(7)%	$ 6,681
Weighted average debt outstanding	$71,392	(25)%	$95,562	5%	$90,646
Average interest rate on outstanding indebtedness(b)	6.3%		6.2%		7.8%
(a) Interest expense on our senior subordinated notes that was paid in kind through the issuance of additional debt in lieu of cash. Our option to pay interest in kind on our senior subordinated notes expired in October 2003	$ 1,196	11%	$ 1,076	49%	$ 721

(b) Calculated as the sum of the interest expense on our outstanding indebtedness, commitment fees and the dividend on our mandatorily redeemable preferred stock divided by the weighted average debt and preferred stock outstanding for the period.

For 2003 compared to 2002, the following were the primary reasons for the changes in our interest expense:

- A decrease in the amount of interest that we paid on our senior credit facility. This decrease in interest expense on our senior credit was due to the following.
  - Our weighted average outstanding debt under our senior credit facility during 2003 was $44.9 million, compared to $74.7 million. See "— Liquidity and Capital Resources — Senior Credit Facility" for changes in the amounts that we have outstanding under our senior credit facility.
  - A decrease in the average interest rate that we owe on outstanding balances under our senior credit facility. In March 2003 we amended our senior credit facility and lowered the interest rate that we owe on borrowings outstanding under our senior credit facility. See "— Capital Commitments — Contractual Obligations" and "Item 7A Quantitative and Qualitative Disclosures About Market Risk — Quantitative Disclosures — Interest Rate Risk" for future interest expense and the sensitivity of interest expense on senior credit facility to changes in short-term interest rates.
- An increase in the amount of interest that we paid on our senior subordinated notes due to an increase in the weighted average senior subordinated notes outstanding from $20.9 in 2002 to $22.2 in 2003. Our outstanding senior subordinated notes balance increased during 2003 because a portion of the interest expense was paid in kind through the issuance of additional debt in lieu of cash. In December 2003, we decreased the amount of senior subordinated notes outstanding and lowered the interest rate on our senior subordinated notes. See "— Capital Commitments — Senior Subordinated Notes" for additional discussion on the amendment to our senior subordinated notes and "— Liquidity and Capital Resources — Senior Subordinated Notes" for additional information about the changes in our senior subordinated notes outstanding.
- Upon our adoption of SFAS 150 in July 2003, we reclassified approximately $8 million of our then outstanding mandatorily redeemable Series A and Series B preferred stock, which has no equity conversion features and must be settled with our assets, to long-term debt. As part of this reclassification, the dividends that have been paid on the reclassified amount since July 2003 have been reported as interest expense. See "— Critical Accounting Policies — New Accounting Pronouncements."

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 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 4.9% compared to 7.2% in 2001. At December 31, 2002, the interest rate on borrowings outstanding under our senior credit facility was 4.5%.

Other income (expense). Other income (expense) primarily includes non-cash gains (losses) resulting from the change in fair market value of oil and gas derivative contracts that did not qualify as hedges, cash gains (losses) on the settlement of these contracts and non-cash gains (losses) related to charges for the ineffective portions of cash flow hedges.

Other income (expense) included:

	Year Ended December 31,		
	2003	2002	2001
	(Dollars in thousands)		
Non-cash gain (loss) due to change in fair market value of derivative contracts that did not qualify as hedges	$ —	$ 384	$ 9,666
Non-cash loss for ineffective portion of hedges	(455)	(122)	—
Cash gain (loss) on settlement of derivative contracts that did not qualify as hedges	—	(559)	(1,492)
Gain (loss) on investments	—	21	(94)
Other	(146)	(34)	—
Total	$(601)	$(310)	$ 8,080

The following table shows the volumes and the weighted average NYMEX reference price for those volumes for our derivative commodity contracts that did not qualify for hedge accounting treatment under SFAS 133 in 2003, 2002 and 2001:

	Year Ended December 31,		
	2003	2002	2001
Natural gas caps			
Volumes (MMbtu)	—	1,810,000	2,450,000
Average ceiling price ($ per MMbtu)	$—	$ 2.63	$ 2.55

Debt conversion expense. Debt conversion expense of $630,000 in 2002 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.

Income tax benefit. Realization of deferred tax assets associated with (i) NOLs, and (ii) existing temporary differences between book and taxable income is dependent upon generating sufficient taxable income of the appropriate character (i.e., ordinary income or capital gain) within the carryforward period available under tax law. Prior to the current year, management believed that it was more likely than not that its deferred tax assets would not be realized and, therefore, reflected a comparable valuation allowance. However, as a result mainly of the increased level of capital expenditures resulting from the September 2003 equity offering, management now believes that Brigham should (i) begin to utilize NOL's, and (ii) have reversals of existing temporary differences between book and taxable income sufficient to result in future deferred tax liabilities. Therefore, we have recognized a deferred tax asset at December 31, 2003, of $2.2 million, consisting of a $1.6 million income tax benefit and a $0.6 million tax effect of unrealized hedging losses. Also at December 31, 2003, management believes it is more likely than not that capital loss carryforwards of approximately $1.8 million may expire unused and, accordingly, has established a valuation allowance of $0.6 million.

Dividends and accretion of mandatorily redeemable preferred stock. We are required 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. We elected to pay dividends in kind in each quarter of 2003, 2002 and 2001.

Upon our adoption of SFAS 150 in July 2003, we reclassified approximately $8 million of our then outstanding mandatorily redeemable Series A and Series B preferred stock that must be settled with our assets to long-term debt. As part of the reclassification, the dividend that has been paid on the reclassified amount since July 2003 has been reported as interest expense. See "— Critical Accounting Policies — New Accounting Pronouncements."

In November and December 2003, CSFB Private Equity used a portion of our mandatorily redeemable Series A and Series B preferred stock that it held to pay for the exercise of the associated warrants. We also redeemed the remaining balance of Series B preferred stock that was not used to pay for the exercise. See "— Capital Commitments — Mandatorily Redeemable Preferred Stock."

The following table shows the effect on our balance sheet for the years ended December 31, 2003, 2002 and 2001 of the issuance of additional shares of preferred stock in lieu of paying cash dividends.

	Year Ended December 31,		
	2003	2002	2001
	(Dollars in thousands)		
Dividends	$ 3,061	$ 2,713	$ 2,347
Accretion of mandatorily redeemable preferred stock	387	239	103
Total	$ 3,448	$ 2,952	$ 2,450
Additional preferred shares issued			
Series A	132,490	134,440	117,358
Series B	30,603	1,226	—

Liquidity and Capital Resources

During 2003, we strengthened our balance sheet and enhanced our financial flexibility through the completion of the equity offering and new senior credit facility, as well as by continuing to build upon the solid financial performances of recent years. Cash will be required to fund capital expenditures for the exploration and development of oil and natural gas properties necessary to offset the inherent declines in production and proven reserves typical in an extractive industry like ours. Future success in growing reserves and production will be highly dependent on our access to cost effective capital resources and our success in economically finding and producing additional reserves. We believe that cash on hand, net cash provided by operating activities, and the unused committed borrowing capacity under our senior credit facility will be adequate to satisfy future financial obligations and liquidity.

In the current environment of higher commodity prices, there may be increased demand for drilling equipment and services, leases and economically attractive prospects, which then may result in less availability and higher costs to us for those resources. Also, we may face additional competition from both domestic and international sources of supply, which may exert a downward pressure on the prices we ultimately receive for our products.

In addition, a significant known trend expected by our management to have an effect on our liquidity is our plan to accelerate our drilling activities in 2004 relative to recent prior years. See "Item 2. Properties," "— Overview" and "— 2004 Outlook" for additional discussion about our 2004 capital expenditure program.

Net Cash Provided by Operating Activities

Net cash provided by operating activities is a function of the prices we receive from the sale of oil and natural gas, which are inherently volatile and unpredictable, production, operating cost, our cost of capital and capital spending. Our asset base, as with other extractive industries, is a depleting one in which each Mcf of natural gas or barrel of oil produced must be replaced or our ability to generate cash flow, and thus sustain our exploration and development activities, will diminish. See "— Risk Factors — Our Future Operating Results May Fluctuate and Significant Declines in Them Would Limit Our Ability To

Invest In Projects" and "— Risk Factors — The Failure To Replace Reserves In The Future Would Adversely Affect Our Production And Cash Flows."

	Year Ended December 31,				
	2003	% Change	2002	% Change	2001
	(Dollars in thousands)				
Net cash flow provided by operating activities	$41,691	44%	$28,973	53%	$18,922

For 2003 compared to 2002, higher commodity prices combined with lower cash interest costs were the primary reasons for the $12.7 million increase in net cash provided by operating activities. The higher commodity prices and lower cash interest costs were partially offset by an increase in production costs. Our working capital deficit at December 31, 2003, was $14.7 million compared to a working capital deficit of $688,000 at December 31, 2002. Working capital is the amount by which current assets exceed current liabilities. It is normal for us to report a working capital deficit at the end of a period. These deficits are primarily the result of accounts payable related to lease operating expenses, exploration and development costs, royalties payable and gas imbalances payable. Settlement of these payables will be funded by cash flows from operations or, if necessary, by additional borrowing under our senior credit facility. Our gas imbalance related to the wells in Home Run Triple Crown and Floyd Fault Block Fields was partially settled in November 2003. Due to the settlement, we borrowed an additional $4 million under our senior credit facility. The settlement reduced the balance of our gas imbalance payable by $11.3 million and reduced the balance of our gas imbalance receivable by approximately $7.2 million. At December 31, 2003, current liabilities included a liability of $2.1 million related to the fair value of hedging contracts.

For 2002 compared to 2001, net cash provided by operating activities increased $10.1 million. These changes were primarily due to an increase in our post-hedge realized sales prices for oil and natural gas and a decrease in interest expense related to our senior credit facility. These changes were partially offset by increases in our lease operating expenses, production taxes, general and administrative expenses and debt conversion cost. At December 31, 2002 we had a working capital deficit of $688,000 compared to a working capital surplus of $1.7 million at December 31, 2001.

Cash Flows from Financing Activities

Over the three year period ended December 31, 2003, we have entered into various financing transactions with the intent of reducing our cost of capital and increasing our liquidity so that we could fund our capital expenditures for the exploration and development of oil and natural gas properties.

Common Stock Transactions

- In February 2003, we issued 248,028 unregistered shares of our common stock to a group of institutional investors led by affiliates of two members of our board of directors. We received no proceeds from the exercise of the warrants as the group elected to execute a cashless exercise of the warrants.

- In June 2003, we issued 408,928 and 206,982 unregistered shares of our common stock to the Bank of Montreal and Société Générale, respectively. We received no proceeds from the exercise of these warrants as both parties elected to execute a cashless exercise of the warrants. Both parties subsequently sold these shares in our common stock sale in September 2003. We received no proceeds from these sales.

- In September 2003, we issued 7,384,090 shares of common stock and received $40 million in net proceeds. The net proceeds from the sale will be used to accelerate the amount of capital that we can spend on our exploration and development program and reduce our outstanding indebtedness. Pending such use to accelerate our exploration and development activities, the net proceeds were used to repay $40 million of the borrowings outstanding under or senior credit facility. See "Item 1. Business," "Item 2. Properties" and "— 2004 Outlook" for further discussion of future capital expenditures.

- In November and December 2003, we required CSFB Private Equity to exercise warrants it held to purchase 11,070,780 shares of our common stock. CSFB Private Equity elected to use shares of our Series A and Series B mandatorily redeemable preferred stock that it held to pay for the exercise prices of the warrants. We received no proceeds from the exercise of the warrants. See "— Capital Commitments — Mandatorily Redeemable Preferred Stock" and "— Results From Operations — Dividends and Accretion of Mandatorily Redeemable Preferred Stock."
- We received $829,000 in net proceeds and issued 309,760 shares of common stock related to the exercise of employee stock options during 2003.
- In December 2002, we issued 550,000 unregistered shares of our common stock to Shell Capital in exchange for its warrant position, including 1,250,000 warrants associated with our senior subordinated notes facility, and to terminate its right to convert $30 million of our senior credit facility into 5,480,769 shares of our common stock. Shell Capital sold the 550,000 shares in our common stock sale in September 2003. We received no proceeds from the exchange or the later sale of the common stock.
- In December 2002, CSFB Private Equity, purchased $10 million of our senior credit facility 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 received no proceeds in this transaction.
- In December 2002, we issued 243,902 unregistered shares of our common stock to a group of institutional investors led by affiliates of two members of our board of directors. We received proceeds of $625,000 from the exercise of the warrants.
- We received $296,000 in net proceeds and issued 132,507 shares of our common stock related to the exercise of employee stock options in 2002.
- We received $252,000 in net proceeds and issued 97,474 shares of our common stock related to the exercise of employee stock options and warrants in 2001.

Mandatorily Redeemable Preferred Stock Transactions

- In December 2002, we issued $10 million ($9.4 million net of issuance costs) in Series B mandatorily redeemable preferred stock and warrants to purchase our common stock. Net proceeds from the offering were used to repay $5 million of the borrowings outstanding under our senior credit facility, fund our exploration and development activities and fund working capital obligations.
- In March 2001, we issued $10 million ($9.8 million net of issuance costs) in Series A mandatorily redeemable preferred stock and warrants to purchase our common stock. Net proceeds from the offering were used to fund our exploration and development activities and working capital obligations.

Senior Credit Facility

We strive to manage the borrowings outstanding under our senior credit facility in order to maintain excess borrowing capacity.

Our future outstanding balances under our senior credit facility are dependent primarily on net cash provided by operating activities, proceeds from other financing activities and proceeds generated from asset dispositions. Our committed borrowing capacity under our senior credit facility is currently $80 million, with a $68.5 million borrowing base that is subject to adjustment on the basis of the present value of estimated future net cash flows from proved oil and gas reserves (as determined by the lender's petroleum engineer). Our unused committed borrowing base capacity under our senior credit facility was $49.5 million at December 31, 2003, and $39.3 million at March 26, 2004. Our senior credit facility matures in March of 2006. See "— Capital Commitments — Senior Credit Facility."

In 2003 we reduced the amount of outstanding borrowings under our senior credit facility by $41 million. The net proceeds from the sale of common stock in September 2003 were used to reduce borrowings outstanding under or senior credit facility by $40 million. We also paid down an additional $4 million and $3 million of the borrowings outstanding under our senior credit facility in the first and second quarters of 2003. These decreases were offset by a drawdown of $6 million in the fourth quarter of 2004 to fund a portion of the settlement of our gas imbalance liability, fund the repayment of $3 million of our outstanding senior subordinated notes and fund the redemption of our Series B mandatorily redeemable preferred stock that remained outstanding after the CSFB conversion of the majority of the Series B preferred stock and associated warrants to common stock. We paid $1.1 million in fees related to the amendment of our senior credit facility in March 2003.

In 2002 we reduced the amount of outstanding borrowings under our senior credit facility by $15 million. We used a portion of the net proceeds from the sale of our Series B mandatorily redeemable preferred stock and warrants to purchase our common stock to pay $5 million of the borrowings outstanding under our senior credit facility. In December 2002, CSFB Private Equity purchased $10 million of our senior credit facility 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 paid $684,000 million in deferred loan fees in 2002.

Senior Subordinated Notes

In connection with the December 2003 amendment of our senior subordinated notes, we reduced the outstanding balance by approximately $3 million. In 2002 and 2001, we borrowed an additional $4 million and $9 million in senior subordinated notes. These additional borrowings were used to fund our exploration and development activities and to fund working capital obligations. We paid $86,000 in fees related to the amendment of our senior subordinated credit agreement in December 2003.

Other Matters

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."

Risk Factors

Our Level of Indebtedness May Adversely Affect Our Cash Available for Operations, Thus Limiting Our Growth, Our Ability to Make Interest and Principal Payments on Our Indebtedness as They Become Due and Our Flexibility to Respond to Market Changes.

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

- We will dedicate a 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 be more vulnerable to economic downturns and our ability to withstand sustained declines in oil and natural gas prices may be impaired.
- Since our indebtedness is subject to variable interest rates, we are vulnerable to increases in interest rates.
- Our flexibility in planning for or reacting to changes in market conditions may be limited.

We may incur additional debt in order to fund our exploration and development activities. A higher level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and reduce our level of indebtedness depends on future performance. General economic conditions, oil and gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flow to pay the interest on our debt, and future working capital, borrowings and equity financing may not be available to pay or refinance such debt.

In addition, under the terms of our senior credit facility, our borrowing base is subject to semi-annual redeterminations based in part on prevailing oil and natural gas prices. In the event the amount outstanding exceeds the redetermined borrowing base, we could be forced to repay a portion of our borrowings. We may not have sufficient funds to make such payments. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets.

We Have Substantial Capital Requirements for Which We May Not Be Able to Obtain Adequate Financing.

We make and will continue to make substantial capital expenditures in our exploration and development projects. Without additional capital resources, our drilling and other activities may be limited and our business, financial condition and results of operations may suffer. We may not be able to secure additional financing on reasonable terms or at all, and financing may not continue to be available to us under our existing or new financing arrangements.

Oil and Natural Gas Prices Fluctuate Widely and Low Prices Could Have a Material Adverse Impact on Our Business and Financial Results by Limiting Our Liquidity and Flexibility to Carry Out Our Drilling Program.

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 and prices often vary significantly. 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 Could Reduce Revenues in a Rising Commodity Price Environment or Expose Us to Other Risks.

In an attempt to reduce our sensitivity to energy price volatility, we may use hedging arrangements that generally result in a fixed price or a range of minimum and maximum price limits over a specified time period. Hedging contracts limit the benefits we would otherwise realize if actual prices rise above the contract price.

Our hedging arrangements expose us to the risk of financial loss in certain circumstances. For example, 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 and reduced our cash flow in 2000 by approximately $1 million. Additionally, 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 our actual results could harm our anticipated profit margins and our ability to manage the risk associated with fluctuations in oil and natural gas prices. We also could be financially harmed if the counter parties to our hedging contracts prove unable or unwilling to perform their obligations under such contracts. Additionally, in the past, some of our hedging contracts required us to deliver cash collateral or other assurances of performance to the counter parties in the event that our payment obligations exceeded certain levels. Future collateral requirements are uncertain but will depend on arrangements with our counter parties and highly volatile natural gas and oil prices.

Exploratory Drilling is a Speculative Activity That May Not Result in Commercially Productive Reserves and May Require Expenditures in Excess of Budgeted Amounts.

Our future rate of growth depends highly upon the success of our exploratory drilling program. Exploratory drilling involves a higher risk that we will not encounter commercially productive natural gas or oil reservoirs than developmental drilling. We cannot 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 pre-drilling 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. In addition, such seismic interpretations are not substantiated without drilling which may even invalidate previously accepted interpretations, require more processing and/or interpretation expense or condemn an area. 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. We may never lease, drill or produce oil or natural gas from these or any other potential drilling locations. We may not be successful in our drilling activities, our overall drilling success rate for activity within a particular province may not be maintained, and our completed wells may not ultimately produce our estimated economically recoverable reserves. Unsuccessful drilling activities could result in a significant decline in our production and revenues and materially harm our operations and financial condition by reducing our available cash and resources.

We are Subject to Various Operating and Other Casualty Risks That Could Result in Liability Exposure or the Loss of Production and Revenues.

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.

We May Not Have Enough Insurance to Cover All of the Risks We Face, Which Could Result in Significant Financial Exposure.

We maintain insurance coverage against some, but not all, potential losses in order to protect against the risks we face. We may elect not to carry insurance if our management believes that the cost of insurance is excessive relative to the risks presented. 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.

We Cannot Control the Activities on Properties We Do Not Operate and Are Unable to Ensure Their Proper Operation and Profitability.

We do not operate all of the properties in which we have an interest. As a result, we have limited ability to exercise influence over operations for these properties. The failure of an operator of our wells to adequately perform operations, or an operator's breach of the applicable agreements, could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including the operator's:

• timing and amount of capital expenditures;

• expertise and financial resources;

• inclusion of other participants in drilling wells; and

• use of technology.

The Marketability of Our Natural Gas Production Depends on Facilities That We Typically Do Not Own or Control Which Could Result in a Curtailment of Production and Revenues.

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 under interruptible or short term transportation agreements. Under the interruptible transportation agreements, the transportation of our gas may be interrupted due to capacity constraints on the applicable system, for maintenance or repair of the system, or for other reasons as dictated by the particular agreements. Our ability to produce and market natural gas on a commercial basis could be harmed by any significant change in the cost or availability of such markets, systems or pipelines.

Lower Oil and Natural Gas Prices May Cause Us to Record Ceiling Limitation Write-Downs Which Would Reduce Our Stockholders' Equity.

We use the full cost method of accounting for costs related to our oil and gas properties. Accordingly, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under full cost accounting rules, the net capitalized cost of oil and gas properties may not exceed a "ceiling limit" that is based upon the present value of estimated future net revenues from proved reserves, discounted at 10%, plus the lower of the cost or fair market value of unproved properties. If net capitalized costs of oil and gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling limitation write-down." This charge does not impact cash flow from operating activities, but does reduce our stockholders' equity. 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 low or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves. Once incurred, a write-down of oil and gas properties is not reversible at a later date.

We Have Had Operating Losses in the Past and May Not be Profitable in the Future.

We may not be profitable in the future. We have recognized the following annual net losses since 1997: $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 write-down 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.

Our Future Operating Results May Fluctuate and Significant Declines in Them Would Limit Our Ability to Invest in Projects.

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.

The Failure to Replace Reserves in the Future Would Adversely Affect Our Production and Cash Flows.

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 and production will decline as reserves are produced.

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, our future exploration and development activities may not result in additional proved reserves, and we may not be able to drill productive wells at acceptable costs.

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. Because most of our reserve estimates are without the benefit of a lengthy production history and are calculated using volumetric analysis, those estimates are less reliable than estimates based on a lengthy production history. Volumetric analysis involves estimating the volume of a reservoir based on the net feet of pay of the structure and an estimation of the area covered by the structure based on seismic analysis.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated natural gas and oil reserves. In accordance with the requirements of the Securities and Exchange Commission, we base the estimated discounted future net cash flows from our proved reserves on prices and costs on the day of estimate. However, actual future net cash flows from our oil and natural gas properties also will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- 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 Securities and Exchange Commission reporting requirements may not 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, and Many of Our Competitors Have Resources in Excess of Our Available Resources.

We operate in the highly competitive areas of oil and natural gas exploration, exploitation, acquisition and production. 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.

We Are Subject to Various Governmental Regulations and Environmental Risks Which May Cause Us to Incur Substantial Costs.

Our business is subject to laws and regulations promulgated by federal, state and local authorities, including the FERC, the Environmental Protection Agency, the Texas Railroad Commission, the TCEQ and the Oklahoma Corporation Commission, relating to the exploration for, and the development, production and marketing of, oil and natural gas, as well as safety matters. 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 federal, state and local environmental laws and regulations, including the CERCLA, the RCRA, the OPA and the Clean Water Act. 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.

Our Business May Suffer if We Lose Key Personnel.

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 have assembled a team of geologists, geophysicists and engineers who have considerable experience in applying 3-D seismic imaging technology to explore for and to develop oil and natural gas. We depend upon the knowledge, skill and experience of these experts to provide 3-D seismic 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 Mr. Brigham, but do not have an employment agreement with any of our other employees.

Our Shares That Are Eligible for Future Sale May Have an Adverse Effect on the Price of Our Common Stock.

Sales of substantial amounts of common stock, or a perception that such sales could occur, could adversely affect the market price of the common stock and could impair our ability to raise capital through the sale of our equity securities. As of December 31, 2003, one of our stockholders, together with its affiliates, owned 13,634,882 shares of our common stock. Furthermore, this stockholder and other stockholders have the right to demand that we file a registration statement under the Securities Act covering the sale of their shares of common stock.

Certain of Our Affiliates Control a Majority of Our Outstanding Common Stock, Which May Affect Your Vote as a Stockholder.

Our directors, executive officers and 10% or greater stockholders, and certain of their affiliates beneficially own a majority 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. In addition, our outstanding Series A preferred stock, our senior credit facility and our senior subordinated notes contain terms restricting our ability to enter into change of control transactions, including requirements to redeem or repay the Series A preferred stock, our senior credit facility and our senior subordinated notes upon a change in control. 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.

Forward Looking Information

This report and the documents incorporated by reference in this annual report on Form 10-K contain forward-looking statements within the meaning of the federal securities laws.

These forward-looking statements include, among others, the following:

- our growth strategies;
- our ability to successfully and economically explore for and develop oil and gas resources;
- anticipated trends in our business;
- our future results of operations;
- our liquidity and ability to finance our exploration and development activities;
- market conditions in the oil and gas industry;
- our ability to make and integrate acquisitions; and
- the impact of governmental regulation.

Forward-looking statements are typically identified by use of terms such as "may," "will," "expect," "anticipate," "estimate" and similar words, although some forward-looking statements may be expressed differently.

You should be aware that our actual results could differ materially from those contained in the forward-looking statements. You should consider carefully the statements under "Risk Factors" and other sections of this report, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*

Management Opinion Concerning Derivative Instruments

We use derivative instruments to manage exposure to commodity prices and interest rate risks. Our objectives for holding derivatives are to achieve a consistent level of cash flow to support a portion of our planned capital spending. Our use of derivative instruments for hedging activities could materially affect our results of operations in particular quarterly or annual periods since such instruments can limit our ability to benefit from favorable price movements. We do not enter into derivative instruments for trading purposes.

Fair Value of Derivative Contracts

The fair value of our derivative contracts is determined based on counterparties' estimates and valuation models. We did not change our valuation methodology during the year ended December 31, 2003. During 2003, we were party to natural gas swap contracts, natural gas floor contracts, oil swaps, oil collar contracts and interest rate swaps. See "Notes to the Consolidated Financial Statements — Note 12" for additional information regarding our derivative contracts. The following table reconciles the changes that occurred in the fair values of our open derivative contracts during 2003.

	Fair Value of Derivative Contracts
Estimated fair value of open contracts at December 31, 2002	$(3,168)
Change fair values of contracts	
Fixed price natural gas swaps	$(3,327)
Natural gas collars	(443)
Fixed price oil swaps	(1,318)
Oil collars	(501)
Interest rate swap	(112)
Contract settlements	
Fixed price natural gas swaps	$ 4,807
Natural gas collars	—
Fixed price oil swaps	1,488
Oil collars	397
Interest rate swap	—
Estimated fair value of open contracts at December 31, 2003	$(2,177)

Based upon the market prices at December 31, 2003, we expect to transfer approximately $2.1 million of the loss included on our balance sheet in accumulated other comprehensive income (loss) to earnings during the next twelve months when transactions actually occur.

Commodity Price Risk

Our primary commodity market risk exposure is to changes in the prices related to the sale of our 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 receive for our 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 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.

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.

As of March 26, 2004, our oil and gas derivative instruments were comprised of swaps and collars.

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, 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.

The following table reflects our open natural gas derivative contracts at December 31, 2003, the associated volumes and the corresponding weighted average NYMEX reference price by quarter.

	2004				2005			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Natural gas swaps:								
Volumes (MMbtu)	295,750	227,500	138,000	92,000	—	—	—	—
Average price ($ per MMBtu)	$ 4.963	$ 4.252	$ 4.180	$ 4.360	$ —	$ —	$—	$—
Unrealized gain/(loss) at 12/31/2003 ($ in thousands)	$ (346)	$ (207)	$ (131)	$ (87)	$ —	$ —	$—	$—
Natural gas collars:								
Volumes (MMbtu)	546,000	409,500	299,000	230,000	202,500	136,500	—	—
Average price ($ per MMBtu)								
Floor	$ 4.125	$ 4.139	$ 4.135	$ 4.150	$ 4.139	$ 4.083	$—	$—
Ceiling	8.433	5.389	5.350	5.662	6.633	5.107	—	—
Unrealized gain/(loss) at 12/31/2003 ($ in thousands)	$ (61)	$ (125)	$ (100)	$ (87)	$ (51)	$ (20)	$—	$—

The following table reflects natural gas derivative contracts that were entered into subsequent to December 31, 2003, the volumes associated with those contracts and the corresponding weighted average NYMEX reference price by quarter.

	2004			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Natural gas collars:				
Volumes (MMbtu)	—	100,100	101,200	34,100
Average price ($ per MMBtu)				
Floor	$—	$ 4.000	$ 4.000	$ 4.000
Ceiling	—	6.830	6.830	6.830

The following table reflects our open oil derivative contracts at December 31, 2003, the associated volumes and the corresponding weighted average NYMEX reference price by quarter.

	2004				2005			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Oil swaps:								
Volumes (Bbls)	29,575	20,475	13,800	9,200	—	—	—	—
Average price ($ per Bbl)	$ 25.35	$ 24.52	$ 23.91	$ 23.80	$ —	$ —	$—	$—
Unrealized gain/(loss) at 12/31/2003 ($ in thousands)	$ (206)	$ (129)	$ (76)	$ (45)	$ —	$ —	$—	$—
Oil collars:								
Volumes (Bbls)	45,500	31,850	18,40	16,100	15,750	6,825	—	—
Average price ($ per Bbl)								
Floor	$ 23.00	$ 23.00	$ 23.00	$ 23.00	$ 23.00	$23.00	$—	$—
Ceiling	30.43	28.92	27.00	26.21	25.85	26.45	—	—
Unrealized gain/(loss) at 12/31/2003 ($ in thousands)	$ (119)	$ (99)	$ (62)	$ (53)	$ (47)	$ (14)	$—	$—

The following table reflects oil derivative contracts that were entered into subsequent to December 31, 2003, the volumes associated with those contracts and the corresponding weighted average NYMEX reference price by quarter.

	2004			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Oil collars:				
Volumes (Bbls)	—	18,200	18,400	6,200
Average price ($ per Bbl)				
Floor	$—	$ 26.00	$ 26.00	$26.00
Ceiling	—	33.55	33.55	33.55

Interest Rate Risk

At December 31, 2003, we had $47.8 million in outstanding debt, of which $28.8 million was fixed rate debt. Our fixed rate debt consists of $20 million in senior subordinated notes and $8.8 million in mandatorily redeemable Series A preferred stock.

The estimated fair value of our senior subordinated notes at December 31, 2003, was $20.1 million.

Dividends on our Series A preferred stock 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 expires in November 2005. The carrying value of the mandatorily redeemable Series A preferred stock approximates its fair value as this is the amount that we would have to pay to extinguish the preferred stock.

The remaining $19 million in outstanding debt at December 31, 2003, was related to borrowings under our senior credit facility. At our option, borrowings under our senior credit facility bear interest at a rate equal to: (i) the base rate of Société Générale plus a margin which fluctuates from 0.5% to 1.5% depending on facility usage or (ii) LIBOR for one, two, three or six months plus a margin which fluctuates from 1.5% to 2.5% depending on facility usage. The weighted average interest rate on these borrowings at December 31, 2003, was 2.7%. A 10% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2003 would equal approximately 27 basis points. Such an increase in interest rates would impact our annual interest expense by approximately $51,000 assuming borrowed amounts under our senior credit facilities remained at $19 million. As the interest rate on borrowings outstanding under our senior credit facility is variable and is reflective of current market conditions, the carrying value approximates the fair value.

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.

Item 9A. *Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

As of the end of period covered by this report, our principal executive officer and principal financial officer carried out an evaluation of the effectiveness of our disclosure controls and procedures. Based on their evaluation, they have concluded that our disclosure controls and procedures effectively ensure that the information required to be disclosed in the reports we file with the SEC is recorded, processed, summarized and reported within the time periods specified by the SEC.

Changes in Internal Controls

There were no changes in our internal controls or in other factors that have materially affected, or are reasonably likely to materially affect, our internal controls subsequent to the date of their evaluation of our disclosure controls and procedures.

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 2004 Proxy Statement for our annual meeting of stockholders to be held on June 3, 2004. The 2004 Proxy Statement will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2003.

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 2004 Proxy Statement, which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2003.

Item 12. *Security Ownership of Certain Beneficial Owners and Management*

The information required by this item is incorporated herein by reference to the 2004 Proxy Statement, which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2003. 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 2004 Proxy Statement, which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2003.

Item 14. ***Principal Accountant Fees and Services***

The information required by this item is incorporated herein by reference to the 2004 Proxy Statement, which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2003.

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 4, 2003 on Item 12. Regulation FD Disclosure, Brigham issued a press release announcing that it plans to force convert Series A preferred stock warrants.

(2) Filed November 12, 2003 on Item 12. Regulation FD Disclosure, Brigham issued a press release announcing its financial results for the quarter ended September 30, 3003.

(3) Filed December 8, 2003 on Item 5. Other Events, regarding adoption of Rule 10b 5-1(c) plans by certain officers.

(4) Filed December 16, 2003 on Item 12. Regulation FD Disclosure, Brigham issued a press release announcing drilling discoveries and provides operational update.

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. The definitions of proved developed reserves, proved reserves and proved undeveloped reserves have been abbreviated from the applicable definitions contained in Rule 4-10(a)(2-4) of Regulation S-X.

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.

All-Sources Finding Costs. The cost associated with acquiring and developing proved oil and natural gas reserves determined on an Mcfe basis by dividing total net capital expenditures, excluding proceeds from the sale of proved oil and gas reserves, associated with drilling and completing of wells, acquiring acreage and geological and geophysical work during the identified period, by the estimated proved reserve additions from exploration and development activities, acquisitions of proved reserves and revisions of previous estimates during the same time period.

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

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 or natural gas liquids.

Completion. The installation of permanent equipment for the production of oil or natural gas. Completion of the well does not necessarily mean the well will be profitable.

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.

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.

Fault. A break in the rocks along which there has been movement of one side relative to the other side.

Fault Block. A body of rocks bounded by one or more faults.

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

Lease Operating Expenses. The expenses, usually recurring, which pay for operating the wells and equipment on a producing lease.

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

Mcf. One thousand cubic feet of natural gas.

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

Mcfe. One thousand cubic feet of natural gas equivalents.

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.

MMcfe/d. MMcfe per day.

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

Net Production. Production that we own 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.

Pay. The vertical thickness of an oil and gas producing zone. Pay can be measured as either gross pay, including non-productive zones or net pay, including only zones that appear to be productive based upon logs and test data.

Pre-tax PV-10%. The pre-tax present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with Securities and Exchange Commission 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 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.

Reserve Replacement Rate. Estimated net reserves added to proved reserves through extensions, discoveries and revisions, divided by production for the period.

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 after-tax present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with Securities and Exchange Commission 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%.

Trend. A geographical area that has been known to contain certain types of combinations of reservoir rock, sealing rock and trap types containing commercial amounts of hydrocarbons.

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 26, 2004.

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, the following persons on behalf of the Registrant and in the capacity indicated have signed this report below as of March 26, 2004.

/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.	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)
/s/ DAVID T. BRIGHAM David T. Brigham	Executive Vice President — Land and Administration and 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

BRIGHAM EXPLORATION COMPANY

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT AUDITORS

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, 2003 and 2002, and the results of their operations and their cash flows for the three years in the period ended December 31, 2003 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.

Additionally, as discussed in Note 2 to the consolidated financial statements, on January 1, 2003, the Company changed its method of accounting for its asset retirement obligations in connection with its adoption of Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations." Additionally, as discussed in Note 2 to the consolidated financial statements, on July 1, 2003, the Company changed its method of accounting for its mandatorily redeemable preferred stock in connection with its adoption of SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity."

PricewaterhouseCoopers LLP

March 25, 2004
Houston, Texas

BRIGHAM EXPLORATION COMPANY

CONSOLIDATED BALANCE SHEETS

	December 31, 2003	December 31, 2002
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 5,779	$ 15,318
Accounts receivable	11,143	11,361
Deferred income taxes	307	—
Other current assets	3,606	6,643
Total current assets	20,835	33,322
Oil and natural gas properties, using the full cost method of accounting		
Proved	277,351	229,991
Unproved	38,506	37,403
Accumulated depletion	(118,546)	(102,414)
	197,311	164,980
Other property and equipment, net	1,219	1,234
Deferred income taxes	1,890	—
Deferred loan fees	2,501	2,391
Other noncurrent assets	460	132
Total assets	$ 224,216	$ 202,059
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 19,806	$ 14,486
Royalties payable	5,280	4,508
Accrued drilling costs	3,916	2,727
Participant advances received	1,179	1,955
Other current liabilities	5,398	10,334
Total current liabilities	35,579	34,010
Senior credit facility	19,000	60,000
Senior subordinated notes	20,000	21,797
Series A Preferred Stock, mandatorily redeemable, $.01 par value, $20 stated and redemption value, 2,250,000 shares authorized, 439,722 shares issued and outstanding at December 31, 2003	8,794	—
Other noncurrent liabilities	2,498	186
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 shares issued and outstanding at December 31, 2002	—	19,540
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, 40,246,729 and 20,618,161 shares issued and 39,086,096 and 19,479,979 shares outstanding at December 31, 2003 and 2002, respectively	402	206
Additional paid-in capital	151,263	93,436
Treasury stock, at cost; 1,160,633 and 1,138,182 shares at December 31, 2003 and 2002, respectively	(4,402)	(4,282)
Unearned stock compensation	(1,816)	(212)
Accumulated other comprehensive income (loss)	(1,040)	(3,047)
Accumulated deficit	(6,062)	(24,352)
Total stockholders' equity	138,345	61,749
Total liabilities and stockholders' equity	$ 224,216	$ 202,059

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

BRIGHAM EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2003	2002	2001
	(In thousands, except per share data)		
Revenues:			
Oil and natural gas sales	$51,545	$35,100	$32,293
Other revenue	132	76	255
	51,677	35,176	32,548
Costs and expenses:			
Lease operating	5,200	3,759	3,486
Production taxes	2,477	1,977	1,511
General and administrative	4,500	4,971	3,638
Depletion of oil and natural gas properties	16,972	14,594	13,211
Depreciation and amortization	629	440	677
Accretion of discount on asset retirement obligations	142	—	—
	29,920	25,741	22,523
Operating income	21,757	9,435	10,025
Other income (expense):			
Interest income	45	119	264
Interest expense, net	(4,815)	(6,238)	(6,681)
Debt conversion expense	—	(630)	—
Other income (expense)	(601)	(310)	8,080
	(5,371)	(7,059)	1,663
Income before income taxes and cumulative effect of change in accounting principle	16,386	2,376	11,688
Income tax benefit	1,636	—	—
Income before cumulative effect of change in accounting principle	18,022	2,376	11,688
Cumulative effect of change in accounting principle	268	—	—
Net income	18,290	2,376	11,688
Less accretion and dividends on redeemable preferred stock	3,448	2,952	2,450
Net income (loss) available to common stockholders	$14,842	$ (576)	$ 9,238
Net income (loss) per share available to common stockholders:			
Basic:			
Income before cumulative effect of change in accounting principle	$ 0.63	$ (0.04)	$ 0.58
Cumulative effect of change in accounting principle	0.01	—	—
	$ 0.64	$ (0.04)	$ 0.58
Diluted:			
Income before cumulative effect of change in accounting principle	$ 0.52	$ (0.04)	$ 0.44
Cumulative effect of change in accounting principle	0.01	—	—
	$ 0.53	$ (0.04)	$ 0.44

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

BRIGHAM EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock Shares	Common Stock Amounts	Additional Paid In Capital	Treasury Stock	Unearned Stock Compensation	Accumulated Other Comprehensive Income (Loss)	Accumulated Deficit	Total Stockholders' Equity
					(In thousands)			
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
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
Comprehensive income (loss):								
Net income	—	—	—	—	—	—	18,290	18,290
Unrealized gain on cash flow hedges	—	—	—	—	—	991	—	991
Tax benefits related to cash flow hedges	—	—	—	—	—	561	—	561
Net losses included in net income	—	—	—	—	—	455	—	455
Comprehensive income								20,297
Issuance of common stock	7,384	74	39,926	—	—	—	—	40,000
Issuance of restricted stock	—	—	1,831	—	(1,831)	—	—	—
Issuance of stock options	—	—	296	—	(296)	—	—	—
Exercise of employee stock options	310	3	826	—	—	—	—	829
Expiration of employee stock options	—	—	(19)	—	—	—	—	(19)
Forfeitures of restricted stock	—	—	—	(10)	2	—	—	(8)
Repurchases of common stock	—	—	—	(110)	—	—	—	(110)
Warrants exercised for common stock	11,935	119	18,415	—	—	—	—	18,534
In kind dividends on Series A mandatorily redeemable preferred stock	—	—	(2,350)	—	—	—	—	(2,350)
Accretion on Series A mandatorily redeemable preferred stock	—	—	(355)	—	—	—	—	(355)
In kind dividends on Series B mandatorily redeemable preferred stock	—	—	(711)	—	—	—	—	(711)
Accretion on Series B mandatorily redeemable preferred stock	—	—	(32)	—	—	—	—	(32)
Amortization of unearned stock compensation	—	—	—	—	521	—	—	521
Balance, December 31, 2003	40,247	$402	$151,263	$(4,402)	$(1,816)	$ (1,040)	$ (6,062)	$138,345

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

BRIGHAM EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2003	2002	2001
	(In thousands)		
Cash flows from operating activities:			
Net income	$ 18,290	$ 2,376	$ 11,688
Adjustments to reconcile net income to cash provided (used) by operating activities:			
Depletion of oil and natural gas properties	16,972	14,594	13,211
Depreciation and amortization	629	440	677
Interest paid through issuance of additional senior subordinated notes	1,196	1,076	721
Interest paid through issuance of additional mandatorily redeemable preferred stock	340	—	—
Amortization of deferred loan fees	1,053	1,191	1,372
Accretion of discount on asset retirement obligations	142	—	—
Market value adjustment for derivative instruments	669	(263)	(9,666)
Loss on investment in Brigham Duke LLC	—	—	94
Stock option compensation expense	—	596	—
Deferred income taxes	(1,636)	—	—
Cumulative effect of change in accounting principle	(268)	—	—
Changes in working capital and other items:			
Accounts receivable	218	(2,248)	164
Other current assets	3,037	(4,534)	(1,550)
Accounts and royalties payable	6,092	10,703	(920)
Other current liabilities	(4,975)	5,060	3,188
Noncurrent assets	—	2	13
Noncurrent liabilities	(68)	(20)	(70)
Net cash provided by operating activities	41,691	28,973	18,922
Cash flows from investing activities:			
Additions to oil and natural gas properties	(45,842)	(27,696)	(34,532)
Proceeds from sale of oil and natural gas properties	427	871	397
Additions to other property and equipment	(349)	(249)	(396)
(Increase) decrease in drilling advances paid	(325)	(132)	960
Net cash used by investing activities	(46,089)	(27,206)	(33,571)
Cash flows from financing activities:			
Proceeds from issuance of common stock, net of issuance costs	40,000	—	—
Redemption of Series B mandatorily redeemable preferred stock	(704)	—	—
Proceeds from issuance of preferred stock and warrants	—	9,356	9,838
Proceeds from issuance of senior subordinated notes and warrants	—	4,000	9,000
Proceeds from exercise of employee stock options	829	296	252
Proceeds from exercise of warrants	—	625	—
Fees paid due to common stock exchange for warrants	—	(50)	—
Repurchases of common stock	(110)	(76)	(67)
Increase in senior credit facility	6,000	—	—
Repayment of senior credit facility	(47,000)	(5,000)	—
Principal payments on senior subordinated notes	(2,993)	—	—
Principal payments on capital lease obligations	—	(28)	(99)
Deferred loan fees paid	(1,163)	(684)	—
Net cash provided (used) by financing activities	(5,141)	8,439	18,924
Net increase (decrease) in cash and cash equivalents	(9,539)	10,206	4,275
Cash and cash equivalents, beginning of year	15,318	5,112	837
Cash and cash equivalents, end of year	$ 5,779	$ 15,318	$ 5,112

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

BRIGHAM EXPLORATION COMPANY

NOTES TO THE 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 the onshore Gulf Coast, the Anadarko Basin and West Texas.

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, asset retirement costs, 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 and asset retirement costs under Statement of Financial Accounting Standards No. 143 (SFAS 143), "Accounting for Asset Retirement Obligations" are amortized using the unit-of-production method based on proved reserves. Capitalized costs of oil and 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. The following were recorded as of December 31 (dollars in thousands):

	2003		2002	
	Value	MMcf	Value	MMcf
Gas imbalance receivable	$2,477	451	$3,656	1,180
Gas imbalance payable	2,064	505	5,650	1,486

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.

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 are reported in other comprehensive income and reclassified to earnings in the periods in which the contracts are settled. The ineffective portion of the cash flow hedges is recognized in current period earnings as other income (expense). 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 cumulative effect of $11.8 million to other comprehensive income to recognize the fair value (liability) of all derivative instruments 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.

Other Comprehensive Income (Loss)

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 (loss) for the years ended December 31, 2003, 2002 and 2001 follow (in thousands):

	2003	2002	2001
Balance, beginning of year	$(3,047)	$ 351	$ —
Cumulative effect of adoption of SFAS 133	—	—	(11,800)
Current period settlements reclassified to earnings	6,692	1,847	9,646
Current period change in fair value of hedges	(5,701)	(5,366)	2,505
Tax benefits related to cash flow hedges	561	—	—
Net losses included in earnings	455	121	—
Balance, end of year	$(1,040)	$(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).

Under SFAS 123, the fair value of each stock option grant is estimated on the date of grant using the Black- Scholes option pricing model with the following weighted average assumptions used for grants during the years ended December 31, 2003, 2002 and 2001:

	2003	2002	2001
Risk-free interest rate	3.7%	4.1%	4.9%
Expected life (in years)	5	7	7
Expected volatility	48%	102%	60%
Expected dividend yield	—	—	—
Weighted average fair value per share of stock compensation	$2.98	$3.44	$2.19

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 amended by SFAS 148, Brigham's net income (loss) and net income (loss) per share for the years ended December 31, 2003, 2002 and 2001 would have been the pro forma amounts indicated below:

	Year Ended December 31,		
	2003	2002	2001
Net income (loss) available to common stockholders (in thousands):			
As reported	$14,842	$ (576)	$9,238
Add back: Stock compensation expense previously included in net income	282	101	295
Effect of total employee stock-based compensation expense, determined under fair value method for all awards	(528)	(513)	(347)
Pro forma	$14,596	$ (988)	$9,186
Net income (loss) per share:			
Basic:			
As reported	$ 0.64	$(0.04)	$ 0.58
Pro forma	0.62	(0.06)	0.57
Diluted:			
As reported	$ 0.53	$(0.04)	$ 0.44
Pro forma	0.52	(0.06)	0.44

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

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 onshore 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

Statement of Financial Accounting Standards No. 141, "Business Combinations" (SFAS 141) and Statement of Financial Accounting Standards, No. 142, "Goodwill and Intangible Assets" (SFAS 142) were issued by the Financial Accounting Standards Board (FASB) in June 2001 and became effective for Brigham on July 1, 2001 and January 1, 2002, respectively. SFAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Additionally, SFAS 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. SFAS 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under SFAS 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment. The appropriate application of SFAS 141 and 142 to oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves is unclear. Depending on how the accounting and disclosure literature is clarified, these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves for both undeveloped and developed leaseholds may be classified separately from oil and gas properties, as intangible assets on our balance sheets. Additional disclosures required by SFAS 141 and 142 would be included in the notes to financial statements. Historically, Brigham, like many other oil and gas companies, has included these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves as part of the oil and gas properties, even after SFAS 141 and 142 became effective.

This interpretation of SFAS 141 and 142 would only affect Brigham's balance sheet classification of oil and gas leaseholds. Brigham's results of operations and cash flows would not be affected, since these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves would continue to be amortized in accordance with accounting rules for oil and gas companies provided in Statement of Financial Accounting Standards No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies."

At December 31, 2003 Brigham had undeveloped leaseholds of approximately $4.2 million that would be classified on its balance sheet as "intangible undeveloped leasehold" and developed leaseholds of an estimated $0.9 million that would be classified as "intangible developed leaseholds" if Brigham applied the interpretation currently being deliberated. This classification would require the disclosures set forth under SFAS 142 related to these interests.

Brigham will continue to classify its oil and gas leaseholds as tangible oil and gas properties until further guidance is provided.

In June 2001, the FASB issued SFAS 143 which 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 adopted this standard as required on January 1, 2003. The following pro forma data summarizes Brigham's net income (loss) and net income (loss) per share for the years ended December 31 2003, 2002 and 2001 as if Brigham had adopted the provisions of SFAS 143 on January 1, 2001. The pro forma asset retirement obligation as of January 1, 2001 would have been $1.7 million.

	Year Ended December 31,		
	2003	2002	2001
	(In thousands, except per share amounts)		
Pro forma asset retirement obligations	$ 2,320	$1,961	$1,680
Net income (loss), as reported	$14,842	$ (576)	$9,238
Pro forma adjustments to reflect retroactive adoption of SFAS 143	(268)	155	469
Pro forma net income (loss)	$14,574	$ (421)	$9,707
Net income (loss) per share:			
Basic — as reported	$ 0.64	$(0.04)	$ 0.58
Basic — pro forma	$ 0.63	$(0.03)	$ 0.61
Diluted — as reported	$ 0.53	$(0.04)	$ 0.44
Diluted — pro forma	$ 0.52	$(0.03)	$ 0.46

In April 2002, the FASB issued Statement of Financial Accounting Standards 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 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 145 is effective for fiscal years beginning after May 15, 2002. Due to the requirements of SFAS 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.

In May 2003, the FASB issued Statement of Financial Accounting Standards No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity" (SFAS 150). SFAS 150 requires an issuer to classify certain financial instruments within its scope, such as mandatorily redeemable preferred stock, as liabilities (or assets in some circumstances). Brigham adopted this standard as required on July 1, 2003. Upon adoption, approximately $8 million of the mandatorily redeemable Series A and B preferred stock were within the scope of SFAS 150 and accordingly were reclassified to long term debt and dividends on the reclassified amount of mandatorily redeemable Series A and B preferred stock have been included in operations as additional interest expense of approximately $340,000. The remaining approximate $18.3 million balance of mandatorily redeemable preferred stock at July 1, 2003, was not reclassified to long term debt because these instruments did not meet the criteria of mandatorily redeemable financial instruments as defined by SFAS 150. SFAS 150 defines a financial instrument as mandatorily redeemable if it embodies an unconditional obligation requiring the issuer to redeem the instrument by transferring its assets at a specified or determinable date(s) or upon an event certain to occur. The remaining balance of mandatorily redeemable Series A and B preferred stock at July 1, 2003, did not embody an unconditional obligation requiring Brigham to transfer its assets to redeem the instruments. The $8 million reclassified to long term debt represents shares of mandatorily redeemable Series A and B preferred stock that must be settled with Brigham assets and thus are within the scope of SFAS 150. The vast majority of these shares were issued to satisfy dividend requirements.

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,	
	2003	2002
Oil and natural gas properties	$ 315,857	$ 267,394
Accumulated depletion	(118,546)	(102,414)
	197,311	164,980
Other property and equipment:		
3-D seismic interpretation workstations and software	2,559	2,445
Office furniture and equipment	2,572	2,337
Accumulated depreciation	(3,912)	(3,548)
	1,219	1,234
	$ 198,530	$ 166,214

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 the periods benefited by these activities. Capitalized costs do not include any costs related to production, general corporate overhead, or similar activities. Capitalized costs are summarized as follows for the years ended December 31, 2003, 2002 and 2001 (in thousands):

	Year Ended December 31,		
	2003	2002	2001
Capitalized certain payroll and other internal costs	$4,621	$4,220	$3,902
Capitalized interest costs	818	878	1,848
	$5,439	$5,098	$5,750

5. Senior Credit Facility and Senior Subordinated Notes

	December 31,	
	2003	2002
	(In thousands)	
Senior Credit Facility	$19,000	$60,000
Senior Subordinated Notes	20,000	21,797
Total Debt	$39,000	$81,797
Less: Current Maturities	—	—
Total Long-Term Debt	$39,000	$81,797

Senior Credit Facility

As of December 31, 2003, Brigham had $19 million in borrowings outstanding under its senior credit facility, which was put in place in March 2003. The senior credit facility provides for a maximum $80 million in commitments, an initial borrowing base of $70 million and matures in March 2006. Principal outstanding under the senior credit facility is due at maturity, with interest due quarterly 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 base rate of Société Générale or

LIBOR (1.1% on December 31, 2003), at Brigham's option, plus a margin that varies according to facility usage (1.55% on December 31, 2003). Obligations under the senior credit facility are secured by substantially all of Brigham's oil and natural gas properties.

The collateral value and borrowing base are redetermined periodically. Based on the most recent redetermination effective December 1, 2003, the borrowing base was set at $68.5 million. The unused portion of the committed borrowing base is subject to an annual commitment fee of 0.5%.

The 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 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. At December 31, 2003, and for the year then ended, Brigham was in compliance with all covenant requirements in connection with its senior credit facility.

Brigham's prior 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.

In December 2002, Brigham entered into a series of transactions whereby a number of warrants and convertible debt rights previously issued to Shell Capital in connection with a prior amendment to the senior credit facility 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 (CSFB), 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, in December 2002 Brigham also issued 500,000 shares of Series B preferred stock and warrants to purchase 2,298,850 million shares of Brigham's common stock for net proceeds of $9.4 million. In addition, Brigham used $5 million of the net proceeds from the Series B preferred offering to repay outstanding indebtedness under its senior credit facility.

Senior Subordinated Notes

As of December 31, 2003, Brigham had $20 million of senior subordinated notes outstanding. The senior subordinated notes are secured obligations ranking junior to Brigham's senior credit facility. The terms of the senior subordinated notes were amended in March 2003 in order to have the covenants and other features of the notes mirror those of the new senior credit facility that was put in place simultaneously (see Senior Credit Facility above). The terms of the senior subordinated notes were amended again in December 2003 resulting in a payment to reduce the outstanding balance of the notes to $20 million, reduce the interest rate and extend the maturity of the notes from October 2005 until March 2009. Prior to the December 2003 amendment, the senior subordinated notes bore interest at 10.75% per annum, were redeemable at Brigham's option for face value at any time and had no principal repayment obligations. As a consequence of the December 2003 amendment, the 10.75% fixed rate coupon was converted to a floating rate coupon. Simultaneous with the completion of the amendment, Brigham entered into an interest rate swap contract to fix the coupon at 8.76% through the new maturity date. In connection with the December 2003 amendment, Brigham agreed to an additional covenant, which requires that Brigham maintain a ratio of risked net present value discounted at 9% to total debt of 1.5 to 1 as defined.

Through October 2003, Brigham had the option to pay up to 50% of the interest payments on the senior subordinated notes through the issuance of additional senior subordinated notes in lieu of cash. For the years ended December 31, 2003, 2002 and 2001, Brigham exercised this option and issued an additional $1.2, $1.1 and $0.7 million, respectively, of senior subordinated notes.

At December 31, 2003 and for the year then ended, Brigham was in compliance with all covenant requirements in connection with its senior subordinated notes.

In connection with the original senior subordinated credit agreement entered into 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 as interest expense over the term of the senior subordinated notes. The warrants were extinguished in December 2002 (see Senior Credit Facility above).

6. Preferred Stock

Series A Mandatorily Redeemable Preferred Stock

The following table reflects the outstanding shares of Series A mandatorily redeemable preferred stock and the activity related thereto for the years ended December 31, 2003 and 2002 (in thousands, except share amounts):

	Year Ended December 31, 2003		Year Ended December 31, 2002	
	Shares	Amounts	Shares	Amounts
Series A mandatorily redeemable preferred stock:				
Balance, beginning of year	1,765,132	$ 19,540	1,630,692	$16,613
Dividends paid in kind	132,490	2,650	134,440	2,689
Accretion	—	355	—	238
	132,490	3,005	134,440	2,927
Forced redemption of October 2000 issuance	(1,000,002)	(9,060)	—	—
Forced redemption of March 2001 issuance	(457,898)	(4,691)	—	—
	(1,457,900)	(13,751)	—	—
Balance, end of year	439,722	$ 8,794	1,765,132	$19,540

In October 2000, Brigham designated 1,500,000 shares of preferred stock as Series A Preferred Stock, and in November 2000, issued 1,000,000 shares of mandatorily redeemable preferred stock (Series A Preferred Stock) and warrants to purchase 6,666,667 shares of Brigham's common stock (Series A — Tranche 1 Warrants) for net proceeds of $19.8 million.

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 dividends through October 2005. The Series A Preferred Stock matures in November 2010 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 Preferred Stock does not generally have any voting rights, except for certain approval rights and as required by law.

The Series A — Tranche 1 Warrants were issued with a term of ten years, an exercise price of $3.00 per share and a right that allowed Brigham to require the exercise of the warrants in the event Brigham's common stock traded above $5.00 per share for 60 consecutive trading days. The exercise price of the Series A — Tranche 1 Warrants was payable either in cash or in shares of the Series A Preferred Stock valued at liquidation value plus accrued dividends. The Series A — Tranche 1 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 accreted to the Series A Preferred Stock dividends during the life of the securities using the effective interest method.

In November 2003, Brigham's common stock traded at an average above $5.00 per share for 60 consecutive trading days and Brigham notified CSFB of its intent to force the exercise of the warrants. The warrants were exercised using shares of Series A Preferred Stock and Brigham received no additional proceeds from the exercise of the warrants.

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

The Series A — Tranche 2 Warrants, which had terms similar to the Series A — Tranche 1 Warrants, had an exercise price of $4.75 per share, later reset to $4.35 in connection with the issuance of Series B Preferred Stock in December 2002, and a right that allowed Brigham to require the exercise of the warrants in the event that Brigham's common stock traded at an average of at least 150% of the exercise price ($6.525 per share) for 60 consecutive trading days. The Series A — Tranche 2 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 accreted to the Series A Preferred Stock dividends during the life of the securities using the effective interest method.

In November 2003, the price of Brigham's common stock averaged at least $6.525 per share for 60 consecutive trading days and Brigham notified CSFB of its intent to force the exercise of the warrants. The warrants were exercised using shares of Series A Preferred Stock and Brigham received no additional proceeds from the exercise of the warrants.

The remaining balance of Series A mandatorily redeemable preferred stock has a mandatory redemption date of October 31, 2010.

Series B Mandatorily Redeemable Preferred Stock

The following table reflects the outstanding shares of Series B mandatorily redeemable preferred stock and the activity related thereto for the years ended December 31, 2003 and 2002 (in thousands, except share amounts):

	Year Ended December 31, 2003		Year Ended December 31, 2002	
	Shares	Amounts	Shares	Amounts
Series B mandatorily redeemable preferred stock:				
Balance, beginning of year	501,226	$ 4,777	—	$ —
Issuance of shares	—	—	500,000	4,752
Dividends paid in kind	30,603	612	1,226	24
Accretion	—	32	—	1
	30,603	644	1,226	25
Forced redemption of December 2002 issuance	(500,002)	(4,784)	—	—
Final redemption of remaining shares	(31,827)	(637)	—	—
	(531,829)	(5,421)	—	—
Balance, end of year	—	$ —	501,226	$4,777

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 (Series B Warrants) to CSFB for net proceeds of $9.4 million. Brigham used $5 million of the net proceeds to reduce borrowings under the senior credit facility. 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 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 had terms similar to the Series A Warrants described above with an exercise price of $4.35 per share and a right that allowed Brigham to require the exercise of the warrants in the event that Brigham's common stock traded 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 accreted to the Series B Preferred Stock dividends during the life of the securities using the effective interest method.

In November 2003, the price of Brigham's common stock averaged at least $6.525 per share for 60 consecutive trading days and Brigham notified CSFB of its intent to force the exercise of the warrants. The exercise price was paid in shares of Series B Preferred Stock and Brigham received no additional proceeds from the exercise of the warrants. Under the terms of the Series B Preferred Stock, Brigham was required to retire the remaining shares of Series B Preferred Stock plus accrued dividends upon the exercise of the warrants because the warrants were exercised using shares of Series B Preferred Stock.

7. Issuance of Common Stock

In December 2003, Brigham issued 2,105,263 shares of Brigham common stock pursuant to the exercise of the Series A — Tranche 2 warrants and 2,298,850 shares of Brigham common stock pursuant to the exercise of the Series B warrants to CSFB. See further discussion above in Note 6.

In November 2003, Brigham issued 6,666,667 shares of Brigham common stock pursuant to the exercise of the Series A — Tranche 1 warrants to CSFB. See further discussion above in Note 6.

In September 2003, Brigham issued 7,384,090 shares of Brigham common stock in a public offering and received proceeds of approximately $40 million, net of underwriting commissions and other offering expenses. The proceeds of the offering will be used to accelerate exploration and development activities and for general corporate purposes. Following the offering, proceeds were used to pay down the new senior credit facility.

In June 2003, Brigham issued 206,982 and 408,928 shares of Brigham common stock pursuant to the exercise under a cashless feature of 338,462 and 661,538 warrants, respectively.

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 Brigham common stock and warrants to purchase 731,707 shares of 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. Asset Retirement Obligations

As referred to in Note 2, Brigham adopted the provisions of SFAS 143 on January 1, 2003. Brigham has asset retirement obligations associated with the future plugging and abandonment of proved properties and related facilities. Prior to the adoption of SFAS 143, Brigham assumed salvage value approximated plugging and abandonment costs. As such, estimated salvage value was not excluded from depletion and plugging and abandonment costs were not accrued for over the life of the oil and gas properties.

The adoption of SFAS 143 resulted in a January 1, 2003 cumulative effect adjustment to record (i) a $1.4 million increase in the carrying values of proved properties, (ii) a $0.8 million decrease in accumulated depletion of oil and natural gas properties and (iii) a $1.9 million increase in other noncurrent liabilities. The net impact of items (i) through (iii) was to record a gain of $0.3 million as a cumulative effect adjustment of a change in accounting principle in Brigham's consolidated statements of operations upon adoption on January 1, 2003.

Brigham has no assets that are legally restricted for purposes of settling asset retirement obligations. The following table summarizes Brigham's asset retirement obligation transactions recorded in accordance with the provisions of SFAS 143 during the year ended December 31, 2003 (in thousands):

	Year Ended December 31, 2003
Beginning asset retirement obligations	$1,931
Liabilities incurred for new wells placed on production	269
Liabilities settled	(22)
Accretion of discount on asset retirement obligations	142
	$2,320

9. Income Taxes

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

	Year Ended December 31, 2003	2002	2001
Current income taxes:			
Federal	$ —	$—	$—
State	—	—	—
Deferred income taxes:			
Federal	(1,636)	—	—
State	—	—	—
	$(1,636)	$—	$—

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,		
	2003	2002	2001
Tax at statutory rate	$ 5,735	$ 832	$ 4,091
Add the effect of:			
Nondeductible expenses	5	223	4
Deductible stock compensation	(118)	(110)	(9)
Valuation allowance adjustments	(7,352)	(945)	(4,086)
Other	94	—	—
	$(1,636)	$ —	$ —

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

	December 31,	
	2003	2002
Deferred tax assets		
Current:		
Net operating loss carryforwards	$ 451	$ —
Noncurrent:		
Net operating loss carryforwards	34,409	34,814
Capital loss carryforwards	634	634
Stock compensation	818	808
Gas imbalances	—	698
Unrealized hedging losses	561	1,066
Derivative assets	276	42
Asset retirement obligations	812	—
Preferred stock dividends as interest expense	119	—
Other	27	32
Noncurrent	37,656	38,094
	38,107	38,094
Deferred tax liabilities		
Current:		
Gas imbalances	(144)	—
Noncurrent:		
Depreciable and depletable property	(35,132)	(29,544)
Derivative liabilities	—	—
Noncurrent	(35,132)	(29,544)
	(35,276)	(29,544)
Net deferred tax asset	2,831	8,550
Valuation allowance	(634)	(8,550)
	$ 2,197	$ —

Realization of deferred tax assets associated with (i) net operating loss carryforwards ("NOLs") and (ii) existing temporary differences between book and taxable income is dependent upon generating sufficient taxable income within the carryforward period available under tax law. At December 31, 2003, management believes that Brigham will (i) begin to utilize NOLs and (ii) have reversals of existing temporary differences between book and taxable income sufficient to recognize a benefit in 2003. Management also believes that it is more likely than not that capital loss carryforwards of approximately $1.8 million may expire unused and, accordingly, has established a valuation allowance of $0.6 million.

At December 31, 2003, Brigham has regular tax NOLs of approximately $99.6 million. Additionally, Brigham has approximately $85.2 million of alternative minimum tax ("AMT") NOLs available as a deduction against future taxable income.

The NOLs expire from 2012 through 2023. The value of these NOLs depends on the ability of Brigham to generate taxable income. A summary of the NOLs follows:

	Regular NOLs	AMT NOLs
Expiration Date:		
December 31, 2012	$13,299	$ 8,675
December 31, 2018	26,411	23,170
December 31, 2019	20,717	20,107
December 31, 2020	12,491	7,566
December 31, 2021	19,095	18,419
December 31, 2022	4,452	4,114
December 31, 2023	3,136	3,142
	$99,601	$85,193

In addition, at December 31, 2003, Brigham has capital loss carryforwards of approximately $1.8 million that expire in varying years through 2007.

Brigham believes it has a $4.5 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,		
	2003	2002	2001
Basic EPS:			
Income (loss) available to common stockholders before cumulative change in accounting principle	$14,574	$ (576)	$ 9,238
Cumulative change in accounting principle	268	—	—
Income (loss) available to common stockholders	$14,842	$ (576)	$ 9,238
Common shares outstanding	23,363	16,138	15,988
Basic EPS:			
Income (loss) available to common stockholders before cumulative change in accounting principle	$ 0.63	$ (0.04)	$ 0.58
Cumulative change in accounting principle	0.01	—	—
Income (loss) available to common stockholders	$ 0.64	$ (0.04)	$ 0.58

	Year Ended December 31,		
	2003	2002	2001
Diluted EPS:			
Income (loss) available to common stockholders before cumulative change in accounting principle	$14,574	$ (576)	$ 9,238
Cumulative change in accounting principle	268	—	—
Income (loss) available to common stockholders	14,842	(576)	9,238
Adjustments for assumed conversions:			
Interest on convertible debt	—	—	826
Dividends and accretion on mandatorily redeemable preferred stock(1)	3,290	—	2,364
	3,290	—	3,190
Income (loss) available to common stockholders before cumulative change in accounting principle — diluted	17,864	(576)	12,428
Cumulative change in accounting principle	268	—	—
Income (loss) available to common stockholders — diluted	$18,132	$ (576)	$12,428
Common shares outstanding	23,363	16,138	15,988
Effect of dilutive securities:			
Convertible debt	—	—	2,564
Warrants	317	—	926
Mandatorily redeemable preferred stock	9,971	—	8,426
Stock options	703	—	301
Potentially dilutive common shares	10,991	—	12,217
Adjusted common shares outstanding — diluted	34,354	16,138	28,205

	Year Ended December 31,		
	2003	2002	2001
Diluted EPS:			
Income (loss) available to common stockholders before cumulative change in accounting principle	$ 0.52	$ (0.04)	$ 0.44
Cumulative change in accounting principle	0.01	—	—
Income (loss) available to common stockholders	$ 0.53	$ (0.04)	$ 0.44

(1) The amount of dividends included in dividends and accretion on mandatorily redeemable preferred stock includes only the dividends paid in kind on the $40 million of mandatorily redeemable preferred stock (2.0 million shares) that were issued with warrants whose exercise price is payable in either cash or in shares of mandatorily redeemable preferred stock.

At December 31, 2003, 2002, and 2001, potential dilution of approximately 1,000,000, 14,300,000 and 3,000,000 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.

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 November 20, 2001, Brigham filed a lawsuit in the District Court of Travis County, Texas, against Steve Massey Company, Inc. ("Massey"). The Petition claims Massey furnished defective casing to Brigham, which ultimately led to the casing failure of the Palmer 347 #5 well and the loss of the Palmer #5 as a producing well. In 2004, the parties agreed in principle to settle the case on terms favorable to Brigham. Brigham will receive approximately $440,000 as a result of this settlement, which will be a reduction to capitalized well costs. In addition, Massey has agreed to drop its $445,819 counterclaim.

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 Safety & Health Administration conducted an inspection and, in October 2003, Brigham settled all issues resulting from that inspection for $70,000.

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. Plaintiffs were seeking unspecified actual and punitive damages. On March 23, 2004, a jury determined that Brigham had no liability in the accidental death of the contractor's employee.

In September 2002, Brigham filed suit in the district court of Matagorda County, Texas, against one of its contractors in connection with the drilling of the Burkhart #1-R well. The suit claims that the contractor breached its contract with Brigham and negligently performed services on the well, resulting in damages of approximately $650,000. The contractor filed a counterclaim for the recovery of approximately $315,000. The parties agreed in principle to settle the case in February 2004. The settlement will result in a payment by the contractor to Brigham and its co-participants. In addition, the contractor will drop its counterclaim. Based on the amount of the settlement, the additional costs that were covered by insurance, and the insurer being subrogated to Brigham's claim, Brigham will not receive any incremental recovery as a result of the settlement.

The operator of the Stonehocker #1 disputed Brigham's ownership interest in the well. In January 2004, the Oklahoma Corporation Commission ruled in favor of Brigham. The operator of the Stonehocker #1 appealed the ruling and the Oklahoma Corporation Commission affirmed its original ruling in March 2004. The operator may now appeal the ruling to the Oklahoma Supreme Court.

A company that relinquished its ownership interest in the Nold #1S well as a result of a non-consent election in the re-completion of the well has asserted that it did not relinquish its entire interest, but rather became subject only to a 400 percent payout provision. In November 2003, the company filed a lawsuit against Brigham for breach of contract. If the suit is successful, it could result in a judgment of as much as $700,000. Brigham has not recorded a contingent liability in connection with this suit. At this point in time, Brigham cannot predict the outcome of this case.

In December 2003, Brigham filed a lawsuit in the United States District Court for the Western District of Texas against another company and a former employee concerning the defendants' misappropriation of Brigham's trade secrets and breach of confidentiality obligations. Defendants have denied any wrongdoing and have asserted a counterclaim against Brigham for alleged tortuous interference with an existing business relationship between the company and its employee. The counterclaim does not specify the amount of damages claimed other than that the damages exceed $75,000 (the jurisdictional limit). At this point in time, Brigham cannot predict the outcome of this case.

As of December 31, 2003, there are 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.

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, 2003 are as follows (in thousands):

2004	$ 910
2005	910
2006	910
2007	455
	$3,185

Future minimum rental payments are not reduced by sublease rental income of approximately $64,000 due in 2004 and $38,000 due in 2005 under noncancelable subleases.

Rental expense for the years ended December 31, 2003, 2002 and 2001 was approximately $851,000, $868,000 and $731,000, 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, 2003, 2002 and 2001:

	2003	2002	2001
Purchaser A	—	19%	45%
Purchaser B	—	—	15%
Purchaser C	13%	15%	—
Purchaser D	3%	11%	—

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.

The following table summarizes the hedging contracts to which Brigham was a party at December 31, 2003, the total natural gas and crude oil production volumes subject to those contacts and the weighted average NYMEX reference price for those volumes:

	Swaps		Collars		
				Weighted Average	
Natural gas	Volumes	Weighted Average Price	Volumes	Floor Price	Ceiling Price
	(MMbtu)	($/MMbtu)	(MMbtu)	($/MMbtu)	
Quarter Ended:					
March 31, 2004	295,750	4.963	546,000	4.125	8.433
June 30, 2004	227,500	4.252	409,500	4.139	5.389
September 30, 2004	138,000	4.180	299,000	4.135	5.350
December 31, 2004	92,000	4.360	230,000	4.150	5.662
March 31, 2005	—	—	202,500	4.139	6.633
June 30, 2005	—	—	136,500	4.083	5.107
Crude oil	(Bbls)	($/Bbl)	(Bbls)	($/Bbl)	
Quarter Ended:					
March 31, 2004	29,575	25.35	45,500	23.00	30.43
June 30, 2004	20,475	24.52	31,850	23.00	28.92
September 30, 2004	13,800	23.91	18,400	23.00	27.00
December 31, 2004	9,200	23.80	16,100	23.00	26.21
March 31, 2005	—	—	15,750	23.00	25.85
June 30, 2005	—	—	6,825	23.00	26.45

The following table summarizes the hedging contracts to which Brigham entered subsequent to December 31, 2003, the total natural gas and crude oil production volumes subject to those contacts and the weighted average NYMEX reference price for those volumes:

	Collars		
		Weighted Average	
Natural Gas	Volumes	Floor Price	Ceiling Price
	(MMbtu)	($/MMbtu)	
Quarter Ended:			
June 30, 2004	101,100	4.000	6.830
September 30, 2004	101,200	4.000	6.830
December 31, 2004	34,100	4.000	6.830
Crude Oil	(Bbls)	($/Bbl)	
Quarter Ended:			
June 30, 2004	18,200	26.00	33.55
September 30, 2004	18,400	26.00	33.55
December 31, 2004	6,200	26.00	33.55

The fair value of hedging contracts is reflected on the balance sheet as detailed in the following schedule. The current asset and liability amounts represent the fair values expected to be included in the results of operations for the subsequent year.

	December 31,	
	2003	2002
Other current liabilities	$2,140	$3,168
Other noncurrent liabilities	40	—
Other noncurrent assets	3	—
Accumulated other comprehensive income	$2,177	$3,168

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 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, 2003:

	Year Ended December 31,		
	2003	2002	2001
Natural gas			
Average price per Mcf as reported (including hedging results)	$ 4.92	$ 3.21	$ 3.11
Average price per Mcf realized (excluding hedging results)	$ 5.68	$ 3.33	$ 4.29
Decrease in revenue (in thousands)	$4,807	$ 712	$8,001
Oil			
Average price per Bbl as reported (including hedging results)	$28.17	$23.55	$24.05
Average price per Bbl realized (excluding hedging results)	$30.79	$25.17	$24.38
Decrease in revenue (in thousands)	$1,885	$1,135	$ 153

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, 2003 and 2002, there were no derivatives that did not qualify as hedging contracts. Brigham recognized $0 million, $0.4 million and $9.7 million in non-cash gains related to changes in the fair values of these derivative contracts and $0 million, $0.6 million, and $1.5 million in losses related to the cash settlement payments made by Brigham to the counterparty for the years ended December 31, 2003, 2002 and 2001, respectively.

For the years ended December 31, 2003 and 2002, ineffectiveness associated with Brigham's derivative commodity instruments designated as cash flow hedges decreased earnings by approximately $0.7 million and $0.1 million, respectively. These amounts are included in other income and expense. There was no ineffectiveness for the year ended December 31, 2001.

Interest rate swap

Periodically, Brigham may use interest rate swap contracts to adjust the proportion of its total debt that is subject to variable interest rates. Under such an interest rate swap contract, Brigham agrees to pay an amount equal to a specified fixed-rate of interest for a certain notional amount and receive in return an amount equal to a variable-rate. The notional amounts of the contract are not exchanged. No other cash payments are made unless the contract is terminated prior to maturity. Although no collateral is held or exchanged for the contract, the interest rate swap contract is entered into with a major financial institution in order to minimize Brigham's counterparty credit risk. The interest rate swap contract is designated as cash flow hedges against changes in the amount of future cash flows associated with Brigham's interest payments on variable-rate debt. The effect of this accounting on operating results is that interest expense on a portion of variable-rate debt being hedged is recorded based on fixed interest rates.

At December 31, 2003, Brigham had an interest rate swap contract to pay a fixed-rate of interest of 8.76% on $20 million notional amount of senior subordinated notes. The $20 million notional amount of the outstanding contract matures in March 2009. As of December 31, 2003, approximately $112,000 of unrealized losses are included in accumulated other comprehensive income (loss) on the balance sheet which represents the fair values of the interest rate swap agreement as of that date. The fair value of the interest rate swap contract is based on quoted market prices and third-party provided calculations, which reflect the present values of the difference between estimated future variable-rate receipts and future fixed-rate payments.

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, 2003 and 2002 was $20.1 million and $24.0 million, respectively. The carrying value of the Series A mandatorily redeemable preferred stock approximates its fair market value because this is the amount that Brigham would be required to pay to extinguish the preferred stock.

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, 2003 and 2002 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 2003, 2002 and 2001, Brigham provided a base match equal to 25% of eligible employee contributions. Based on attainment of performance goals established at the beginning of each fiscal year, Brigham matched an additional 41%, 62.5% and 17% of eligible employee contributions made during 2003, 2002 and 2001, respectively. Brigham contributed $232,000, $260,000 and $102,000 to the 401(k) plan for the years ended December 31, 2003, 2002 and 2001, respectively, to match eligible contributions by employees.

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 provide incentive and reward key employees whose performance may have a significant impact on the success of Brigham. As amended by stockholder resolution in May 2003, the number of shares available under the plan is equal to the lesser of 4,387,500 or 15% of the total number of shares of common stock outstanding. 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 had issued approximately 85,000 incentive awards in excess of the amount then currently authorized by the plan. Brigham stockholders approved an increase in the total shares available for incentive awards as noted above in May 2003. As a result, the grant date for the 85,000 options is considered May 2003 for accounting purposes. The exercise price for these options was originally set at the market value of Brigham's common stock, however as of May 2003, it was less than the fair market value of Brigham's common stock at that date. Accordingly, Brigham recognized approximately $156,000 of unearned stock compensation and is amortizing this amount to compensation expense over the vesting period of the options. With the exception of these 85,000 options, 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 a certain departing employee's stock options and extended the time limitation for exercising that employee's 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 director stock option plan under which stock options are awarded to non-employee directors. In May 2003, the plan was amended by stockholder resolution to increase the number of shares available for issuance to 430,000 shares of common stock. Options granted under this plan have an exercise price equal to the fair market value of Brigham common stock on the date of grant and generally vest over five years.

The following table summarizes activity under the incentive plans for each of the three years ended December 31, 2003:

	Shares	Weighted-Average Exercise Price
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	481,000	4.12
Options forfeited or cancelled	(177,129)	(3.25)
Options exercised	(132,507)	(2.23)
Options outstanding December 31, 2002	1,788,135	3.00
Options granted	1,127,500	6.46
Options forfeited or cancelled	(23,200)	(3.49)
Options exercised	(309,760)	(2.68)
Options outstanding December 31, 2003	2,582,675	$ 4.78

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, 2003. 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, 2003:

	Options Outstanding			Options Exercisable	
Exercise Price	Number Outstanding at December 31, 2003	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable at December 31, 2003	Weighted-Average Exercise Price
$1.55 to $1.83	169,500	3.1 years	$1.83	131,200	$1.83
2.38 to 3.41	588,925	4.4 years	3.16	269,483	2.93
3.61 to 5.19	802,250	5.0 years	4.08	243,950	3.95
6.31 to 14.38	1,022,000	6.7 years	6.75	12,000	6.98
$1.55 to $14.38	2,582,675	5.4 years	$4.78	656,633	$3.14

Restricted Stock

During the year ended December 31, 2003, Brigham issued 350,000 restricted shares of common stock as compensation to officers and key employees of Brigham. The restricted shares vest over five years. Brigham recognized approximately $1.8 million of unearned stock compensation and will amortize this amount to compensation expense over the vesting period of the restricted stock. The following table reflects the outstanding restricted stock awards and activity related thereto for the year ended December 31, 2003:

	Year Ended December 31, 2003	
	Number of Shares	Weighted-Average Price
Restricted Stock Awards:		
Shares granted	350,000	$5.23
Lapse of restrictions	—	—
Restricted shares outstanding at the end of the year	350,000	$5.23

16. Related Party Transactions

During the years ended December 31, 2003, 2002, and 2001, Brigham incurred costs of approximately $2.0 million, $1.1 million and $0.4 million, respectively, in fees for land acquisition services performed by a company owned by a brother of Brigham's Chairman, 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, 2003 and 2002, Brigham had recorded a liability in accounts payable of approximately $262,000 and $0, respectively, related to services performed by this company.

Mr. Harold Carter, 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 $30,000, $45,000, and $44,000 for the years ended December 31, 2003, 2002, and 2001, respectively. Additional disbursements totaling approximately $12,000, $12,000, and $6,000 were made during 2003, 2002, and 2001, respectively, for the reimbursement of certain expenses. At December 31, 2003 and 2002, there were no payables related to these services recorded by Brigham.

At December 31, 2003 and 2002 Brigham had short-term accounts receivable from Mr. Steven Webster, a director of Brigham, of approximately $8,300 and $94,000, respectively. These receivables represent the director's share of costs related to his working interest ownership in the Staubach #1, Burkhart #1R and Matthes-Huebner #1 wells that are operated by Brigham. Mr. Webster obtained his interest in these wells through an exploration and production company that is not affiliated with Brigham.

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 Chief Financial Officer and 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 Citation Crude Marketing, Inc. approximately 49,000 barrels of oil with a value of $1.6 million during 2003 and 212,000 barrels of oil with a value of $5.6 million to during 2002.

From time to time, in the normal course of business, Brigham has engaged a drilling company in which Mr. Steven Webster, one of Brigham's current directors, owns stock and serves on the board of directors. Total payments to the drilling company during 2003 and 2002 were $1.2 million and $0.4 million, respectively. At December 31, 2003, Brigham owed the drilling company approximately $0.3 million. At December 31, 2002, Brigham owed the drilling company approximately $0.4 million.

From time to time, in the normal course of business, Brigham has engaged a service company in which Mr. Hobart Smith, one of Brigham's current directors, owns stock and serves as a consultant. Total payments to the service company during 2003 and 2002 were $478,000 and $130,000, respectively. At December 31, 2003 and 2002, Brigham owed the service company approximately $237,000 and $76,000, respectively.

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. Mr. Steven Webster, 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, 2003 and 2002, Brigham was owed $206,000 and $413,000, respectively, by Carrizo for exploration and production activities. Brigham owed Carrizo $50,000 and $11,000 at December 31, 2003 and 2002, 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; and (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 2003 and 2002 for exploration, development and production operations were $0 and $189,000, respectively. Total amounts paid to Brigham by Aspect, or on their behalf, during 2003 and 2002 for exploration, development and production operations were $91,000 and $1,008,000, respectively. There were no amounts owed by Brigham to Aspect at December 31, 2003 or 2002. Aspect owed Brigham $69,000 and $312,000 at December 31, 2003 and 2002, respectively, for various oil and gas exploration and production activities. Brigham was also owed $2,800 by Aspect Management Corp., an affiliate of Aspect, at December 31, 2002 for joint venture operations.

17. Supplemental Cash Flow Information

	Year Ended December 31,		
	2003	2002	2001
Cash paid for interest	$ 2,447	$ 3,974	$4,257
Noncash investing and financing activities:			
Increase in current liabilities for deferred loan fees to be paid in future	—	—	200
Dividends and accretion on mandatorily redeemable preferred stock	3,448	2,952	2,450
Conversion of senior credit facility to common stock	—	10,000	—
Conversion of preferred stock to common stock via exercise of warrants	18,534	—	—
Issuance of restricted stock	1,831	—	—
Issuance of stock options	296	—	—

18. Other Assets and Liabilities

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

	December 31,	
	2003	2002
Gas imbalance receivables	$2,477	$3,656
Deposits	—	1,909
Other	1,129	1,078
	$3,606	$6,643

Deposits are amounts held by Brigham's derivative counterparty.

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

	December 31,	
	2003	2002
Gas imbalance liabilities	$2,064	$ 5,650
Derivative liabilities	2,141	3,168
Other	1,193	1,516
	$5,398	$10,334

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.

Costs Incurred and Capitalized Costs

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

	December 31, 2003	2002	2001
Costs incurred for the year:			
Exploration	$20,732	$12,693	$18,210
Property acquisition	5,037	3,213	3,437
Development	22,285	13,301	14,353
Proceeds from participants	(793)	(703)	(135)
	$47,261	$28,504	$35,865

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, 2003 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, 2003	2002	2001	Prior Years	Total
Property acquisition	$2,624	$ 627	$1,468	$ 8,957	$13,676
Exploration	2,570	935	112	18,348	21,965
Capitalized interest	503	527	1,021	814	2,865
Total	$5,697	$2,089	$2,601	$28,119	$38,506

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. 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, 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
Revisions of previous estimates	(6,148)	176
Extensions, discoveries and other additions	22,479	1,067
Production	(6,356)	(720)
Proved reserves at December 31, 2003	109,403	4,130
Proved developed reserves at December 31:		
2000	39,271	1,802
2001	38,633	2,609
2002	42,161	2,330
2003	49,920	2,863

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

	December 31, 2003	2002	2001
Future cash inflows	$ 737,544	$ 601,081	$301,201
Future production costs	(123,176)	(82,689)	(47,430)
Future development costs	(58,978)	(48,668)	(36,983)
Future income tax expense	(138,118)	(104,724)	(34,062)
Future net cash inflows	417,272	365,000	182,726
10% annual discount for estimated timing of cash flows	(155,674)	(125,302)	(61,802)
Standardized measure of discounted future net cash flows	$ 261,598	$ 239,698	$120,924

The base sales prices for Brigham's reserve estimates were as follows:

	Natural Gas (MMbtu)	Oil (Bbl)
December 31, 2003	$5.83	$32.55
December 31, 2002	4.74	31.25
December 31, 2001	2.57	19.84

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, 2003	2002	2001
Beginning of period	$239,698	$120,924	$ 359,228
Sales of oil and natural gas produced, net of production costs	(51,126)	(31,475)	(27,296)
Development costs incurred	14,370	8,625	8,310
Extensions and discoveries	91,383	60,872	41,278
Sales of minerals-in-place	—	(1,064)	(22,476)
Net change of prices and production costs	20,822	136,808	(322,047)
Change in future development costs	11,281	(8,000)	(15,956)
Changes in production rates and other	(65,967)	(17,003)	(29,545)
Revisions of quantity estimates	(15,063)	(2,876)	(22,676)
Accretion of discount	30,737	14,681	49,766
Change in income taxes	(14,537)	(41,794)	102,338
End of period	$261,598	$239,698	$ 120,924

21. Quarterly Financial Data (Unaudited)

	Year Ended December 31, 2003			
	Quarter 1	Quarter 2	Quarter 3	Quarter 4
Revenue	$14,677	$12,170	$13,213	$11,617
Operating income	7,393	4,911	5,590	3,863
Net income:				
Income available to common stockholders before cumulative effect of change in accounting principle	5,248	2,385	3,343	3,598
Cumulative effect of change in accounting principle	268	—	—	—
Net income available to common stockholders	$ 5,516	$ 2,385	$ 3,343	$ 3,598
Net income per share:				
Basic:				
Income available to common stockholders before cumulative effect of change in accounting principle	$ 0.27	$ 0.12	$ 0.16	$ 0.11
Cumulative effect of change in accounting principle	0.01	—	—	—
Net income available to common stockholders	$ 0.28	$ 0.12	$ 0.16	$ 0.11
Diluted:				
Income available to common stockholders before cumulative effect of change in accounting principle	$ 0.19	$ 0.10	$ 0.13	$ 0.10
Cumulative effect of change in accounting principle	0.01	—	—	—
Net income available to common stockholders	$ 0.20	$ 0.10	$ 0.13	$ 0.10

	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) available to common stockholders	(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)

CORPORATE MANAGEMENT

Ben "Bud" M. Brigham

President
Chief Executive Officer
Chairman of the Board

Eugene B. Shepherd, Jr.

Executive Vice President &
Chief Financial Officer

David T. Brigham

Executive Vice President of
Land and Administration &
Director

A. Lance Langford

Executive Vice President of
Operations

Jeffery E. Larson

Executive Vice President of
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 June 3, 2004 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

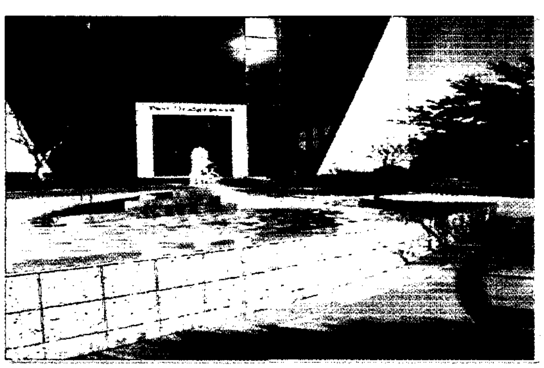
Brigham completed its initial public offering of common stock on May 8, 1997. Brigham's common stock trades on The Nasdaq Stock Market under the symbol BEXP.

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

6300 Bridge Point Parkway, Building 2, Suite 500
Austin, Texas 78730
Phone: 512.427.3300   Fax: 512.427.3400



BOARD OF DIRECTORS

(left to right)

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

David T. Brigham
Executive Vice President of
Brigham Exploration Company

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

Stephen C. Hurley
Executive Vice President of Hunt Oil Company

Steven A. Webster
Chairman of Global Energy Partners

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

Hobart A. Smith
Consultant for Smith International, Inc.

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

CORPORATE INFORMATION

Independent Auditors

PricewaterhouseCoopers LLP, Dallas, Texas

Legal Counsel

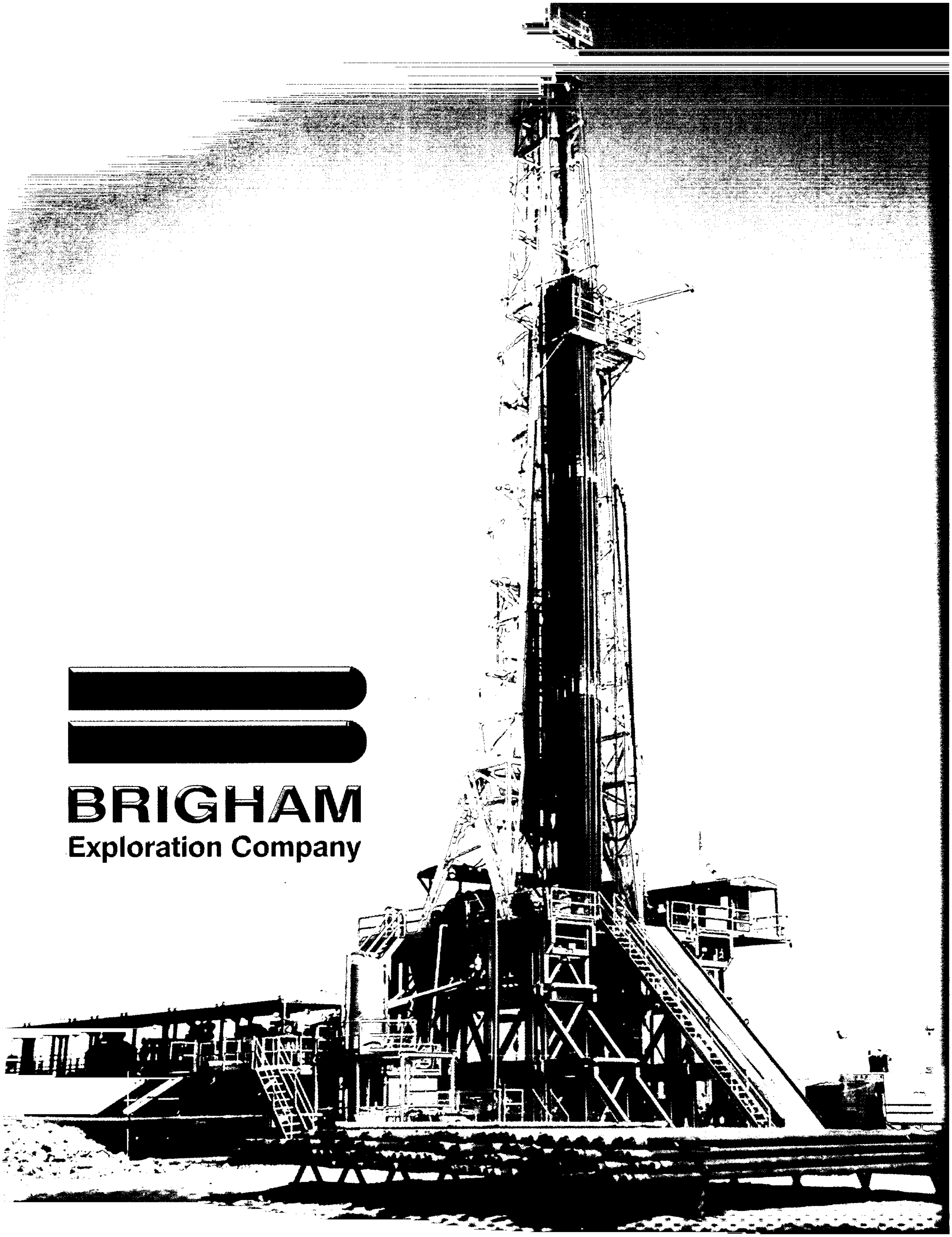
Thompson & Knight L.L.P., Dallas, Texas

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

500 BRIDGE POINT PARKWAY, BLDG. 2, SUITE 500, AUSTIN, TEXAS 78730 512.427.3300 www.bexp3d.com