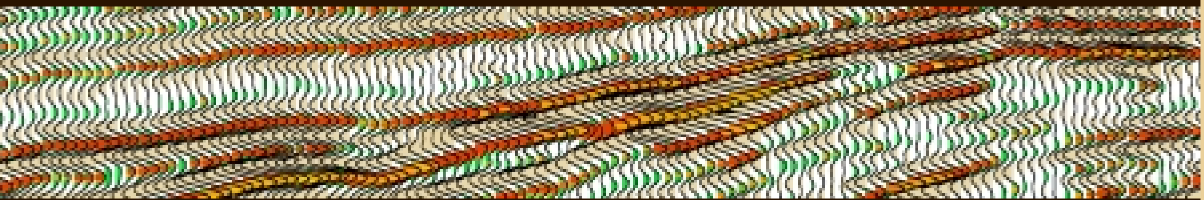
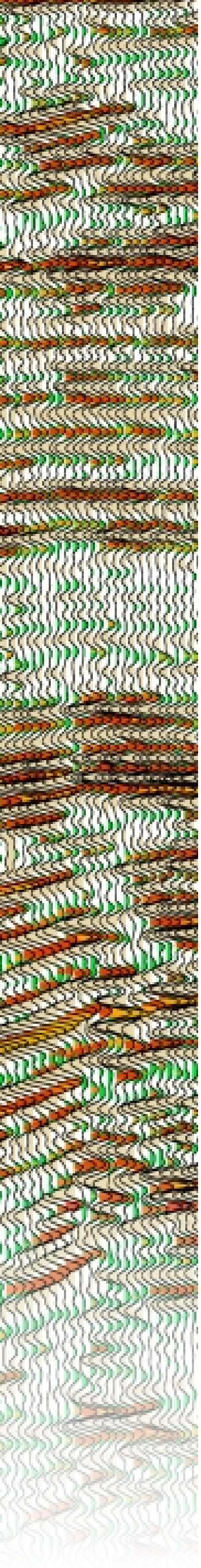
Annual Report
1998



BRIGHAM
Exploration Company



Corporate Profile

Brigham Exploration Company (Nasdaq:BEXP) is an independent exploration and production company that applies 3-D seismic imaging and other advanced technologies to systematically explore and develop onshore natural gas and oil provinces in the United States. Brigham focuses its exploration activities primarily in three core provinces: the Anadarko Basin of western Oklahoma and the Texas Panhandle, the onshore Gulf Coast of Texas and Louisiana and West Texas. Since its inception in 1990, Brigham has achieved rapid growth in its acquisition of 3-D seismic data, identification of potential drilling locations, discovery of proved reserves and production volumes.

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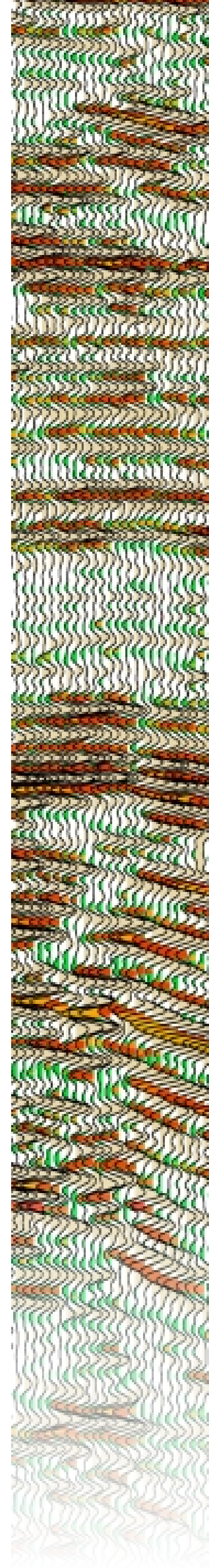

For a glossary of certain terms and abbreviations used throughout this report, please refer to the 1998 Form 10-K report included herein

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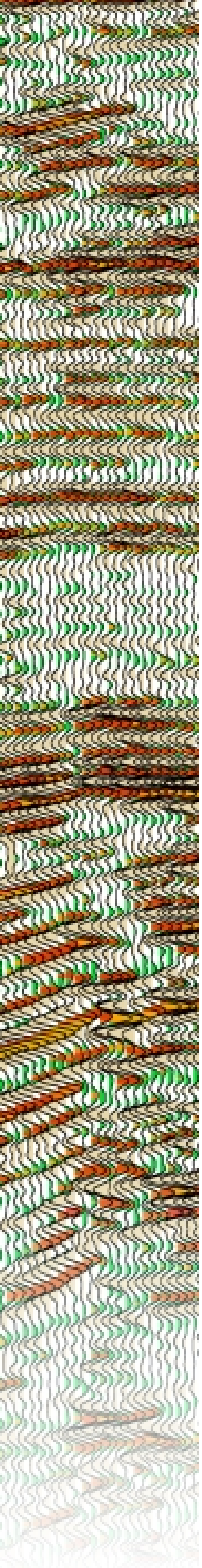


Company Overview

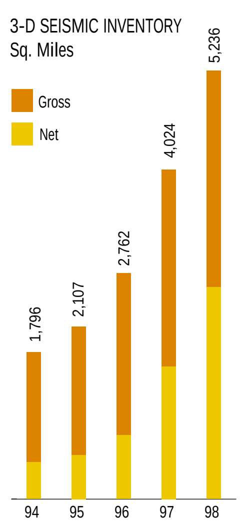
Brigham Exploration Company was founded in 1990 to capitalize on opportunities available to establish an innovative, growth-oriented independent exploration and production company through the use of onshore 3-D seismic imaging technology. The Company's distinctive business model is centered on the core belief that control of 3-D seismic data in proven natural gas and oil producing regions provides a significant competitive advantage to explore for new natural gas and oil reserves. Since its inception, Brigham has assembled a significant 3-D seismic knowledge base which has led to the identification and capture of a substantial number of potential drilling locations. The Company is in the early stages of monetizing its multi-year inventory of onshore drilling locations.

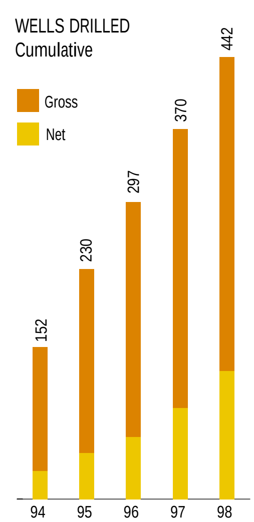
Brigham's business strategy is to achieve superior growth in shareholder value through the application of its systematic approach to explore for natural gas and oil. The Company's exploration process emphasizes the integrated use of 3-D seismic imaging and other advanced technologies to reduce drilling risks and finding costs, thereby increasing returns on investment. Brigham's long-term growth strategy consists of the following key elements:

PROSPECT CAPTURE	Acquiring 3-D seismic data in proven producing trends to identify and capture potential drilling locations
INCREASED EQUITY INTERESTS	Retaining significant working interests in its exploration projects to capture a greater share of the reserves discovered
IMPACT PROSPECTS	Identifying higher potential, higher impact prospects
INVENTORY MONETIZATION	Generating reserves and cash flow from its 3-D seismic investments by focused drilling of its 3-D delineated locations

HIGHLIGHTS

- Over 5,000 square miles of 3-D seismic acquired
- More than 440 3-D delineated wells drilled
- 64% aggregate drilling success rate
- 1998 production more than doubled to 6.6 Bcfe
- 98 Bcfe of net proved reserves at year-end 1998
  - 73% natural gas
  - 57% developed
- 700 estimated remaining potential drilling locations





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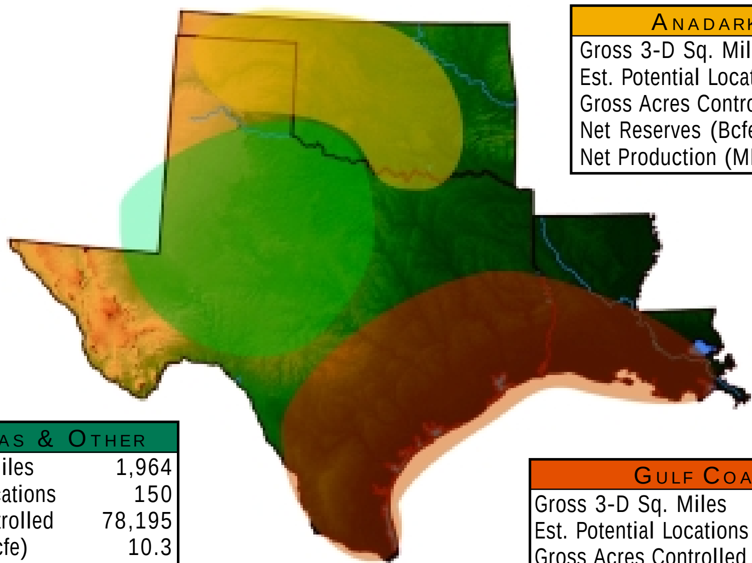
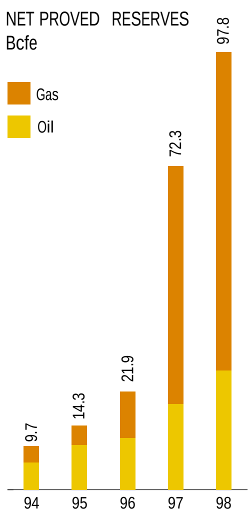


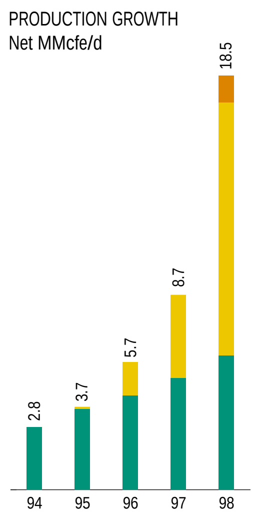
Anadarko Basin	
Gross 3-D Sq. Miles	2,124
Est. Potential Locations	430
Gross Acres Controlled	216,473
Net Reserves (Bcfe)	64.0
Net Production (MMcfe/d)	10.5

West Texas & Other	
Gross 3-D Sq. Miles	1,964
Est. Potential Locations	150
Gross Acres Controlled	78,195
Net Reserves (Bcfe)	10.3
Net Production (MMcfe/d)	4.3

Gulf Coast	
Gross 3-D Sq. Miles	1,148
Est. Potential Locations	120
Gross Acres Controlled	120,660
Net Reserves (Bcfe)	23.5
Net Production (MMcfe/d)	3.6

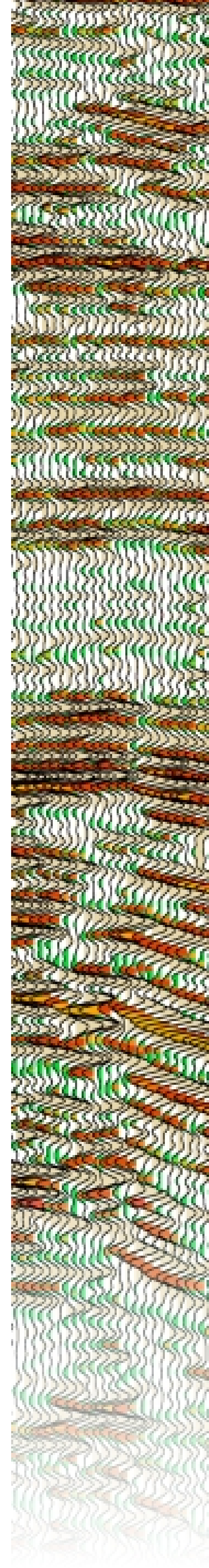
Brigham focuses its exploration activities in provinces where it believes 3-D technology may be effectively applied and which it believes offer relatively large potential reserve volumes per well and per field, high potential production rates and multiple producing objectives. The Company's assets are concentrated primarily in three core provinces: the Anadarko Basin of western Oklahoma and the Texas Panhandle; the onshore Gulf Coast of Texas and, to a lesser extent, the transition zone of Louisiana; and West Texas. As a result of the current low oil price environment, Brigham is concentrating substantially all of its 3-D seismic and drilling activities in its Anadarko Basin and Gulf Coast provinces, targeting predominately natural gas prospects with higher reserve and production potential at lower finding costs.





Competitive Advantages

- Substantial 3-D seismic knowledge base
- Breadth of technical expertise
  - 20 geophysicists and geologists
  - Over 300 aggregate years experience
- Projects generated and controlled internally
- Multi-year drilling inventory
- Innovative business model



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Letter to Shareholders

Looking back, 1998 was a very challenging year for our industry. The year began with $18.00 oil and $2.25 gas, yet ended with $12.00 oil and $1.95 gas. Aggressive growth plans in a relatively capital rich environment were quickly supplanted by survival strategies in a low commodity price and capital scarce environment. What a difference a year makes.

Brigham Exploration Company began 1998 much as we finished 1997, aggressively capturing prospects through our systematic 3-D seismic acquisition approach. We were successful in this area in 1998, as evidenced by our record net 3-D seismic acquisition and our rapidly growing prospect inventory in our Anadarko Basin and Gulf Coast provinces. We were also successful in achieving our goals for net wells drilled and drilling success rates, resulting in 35% growth in proved reserves and 113% growth in production volumes. Despite these accomplishments, however, our reserve base and capital availability at year-end 1998 fell below our expectations.

The most significant challenges in optimizing our Company's growth during 1998, even with a successful core business model, were fluctuating commodity prices and the associated unpredictable access to capital. As commodity prices fell during the year, public, private and industry capital markets tightened or closed altogether, making it much more difficult to finance our aggressive capital expenditures. This was becoming evident in the second quarter when we withdrew our planned $40 million common stock offering. However, late in the third quarter we were pleased to reach an agreement with a sophisticated, high quality energy investor, Enron Capital & Trade Resources, for a $50 million debt and equity placement. Also in the third quarter, in response to deteriorating industry conditions, we began to reduce our non-drilling operational activity. Despite this adjustment, we invested approximately $41 million on 3-D seismic and land in 1998, or roughly half of our total capital expenditures for the year.

Our substantial 3-D seismic and land expenditures over the last several years has provided our Company with a rare and valuable resource - a multi-year inventory of high quality, high potential drilling locations. We firmly believe the combination of our deep, fresh prospect inventory and the current low cost drilling environment creates a compelling opportunity to profitably realize value from our past investments. Therefore, we have eliminated our plans to assemble new 3-D seismic projects in 1999 and will focus our personnel and capital resources on drilling our highest quality locations in inventory, concentrating on those plays and projects where we have achieved our best results.

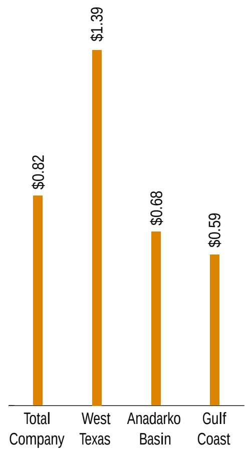
We acquired 1,213 gross square miles of 3-D SEISMIC during 1998 with an average working interest of 80%, or a record 968 net square miles. Our Company has completed two successive years of highly aggressive prospect capture utilizing 3-D seismic technology, having acquired nearly 2.5 times as much net 3-D seismic than in our six prior years combined. Consistent with our long-term growth strategy, virtually all of our new 3-D seismic projects during the past two years are in our higher potential Anadarko Basin and Gulf Coast provinces.

1999 Objectives

- Direct resources to drilling of existing 3-D prospect inventory
- Improve return on investment by focusing on highest grade prospects in Anadarko Basin and Gulf Coast
- Access capital to accelerate the monetization of sizeable 3-D seismic project portfolio
- Pursue creative opportunities to leverage activities in current industry environment
- Optimize business strategy and resources to preserve and realize inherent asset value captured to date

In hindsight, we certainly would have moderated our 3-D seismic expenditures had we anticipated the difficult industry environment. Now, however, these investments are easily our best resource. We may possibly have the largest onshore 3-D seismic inventory, and thus 3-D delineated prospect inventory, of any domestic independent. We are rich with this critical fuel for future growth, providing us with a multi-year prospect inventory to monetize.

NET DRILLING COSTS PER
1990-1998



In our 1998 DRILLING PROGRAM, we drilled 72 gross and 38 net wells, incurring net drilling expenditures of approximately $37 million. We achieved a net drilling success rate of 70% in 1998, which compares favorably to our historical 63% net success rate. Through our 3-D delineated drilling program, we added 32 Bcfe of net proved reserves, including revisions to previous reserve estimates. As a result, we increased our net proved reserves by 35% and replaced more than 465% of our net volumes produced during the year. Excluding revisions, our net proved reserve additions in 1998 totaled approximately 59 Bcfe.

Despite the overall growth in reserves and production achieved from our drilling program, our Company's drilling profitability in 1998 was lower than our historical results and our expectations entering the year. While we had a number of drilling successes in 1998, these were partially offset by seven disappointing high working interest wells drilled late in 1998. Three of these wells were proved undeveloped locations directly offsetting our 1997 Christopher 84 #1 Lower Morrow discovery in the Anadarko Basin. These three wells constituted the majority of our negative revisions in 1998. We also had four relatively high potential exploration wells in the fourth quarter, in which we retained working interests in excess of 75%, which were either dry or that did not perform as anticipated subsequent to completion. Two of these wells were in the Wilcox trend of South Texas, and the other two were in the Anadarko Basin. We have learned a great deal from these high interest drilling disappointments, and we will apply this enhanced knowledge base to our 1999 drilling program.

As a result, our net drilling expenditures per Mcfe added in 1998 (including revisions) was $1.17, significantly higher than our historical drilling cost average of $0.64 per Mcfe achieved from our inception in 1990 through 1997. While the results of our 1998 drilling program fell short of our expectations, we also experienced disappointing drilling returns in 1993 and 1995. However, we are fortunate that we have enjoyed more good drilling years, such as 1992, 1994, 1996 and 1997, than bad ones. Inclusive of our 1998 drilling results, our Company's inception-to-date net drilling cost average is $0.82 per Mcfe added, a level we believe is below industry average. More importantly, our inception-to-date net drilling costs in our Anadarko Basin and Gulf Coast provinces, where all of our planned 1999 drilling is concentrated, are only $0.68 and $0.59 per Mcfe added, respectively. Our focus in these two provinces should contribute to improved drilling profitability and growth going forward.

Our ACCOMPLISHMENTS in 1998 include several major bright spots that we consider indicative of our Company's future. In Gulf Coast exploration, a "bright spot", or amplitude anomaly, is a 3-D seismic attribute which, under the right circumstances, can be a direct indicator of hydrocarbons, thereby significantly reducing dry hole risk. Our Company and others have

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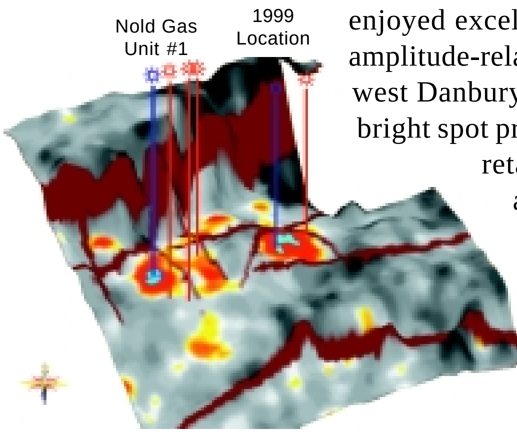


Lower Frio amplitude attribute illustration of Brigham's Southwest Danbury Project.

enjoyed excellent results exploring in the Gulf Coast region with amplitude-related prospects. Our 1998 Frio discovery in the Southwest Danbury Project is an example of a successfully drilled 3-D bright spot prospect. The Brigham Nold Gas Unit #1, in which we retained a 46% working interest, has produced at an average rate of 2.6 MMcfe of natural gas per day since the well began flowing to sales in August 1998. We are fortunate to have a significant inventory of such 3-D bright spot prospects in our portfolio of Gulf Coast projects. In late 1998, we spud an exploratory well to test one of these prospects also in our Southwest Danbury Project, which is a similar, though larger, amplitude-related prospect than our Nold Gas Unit #1 discovery. This well, in which we retained an 83.5% working interest, reached the targeted Frio objective and was in the process of completing in late March 1999.

Our most significant discovery of 1998 occurred in our Gulf Coast province in our Diablo Project, where we have a 34% working interest in a deep Vicksburg exploration play. Our first Vicksburg test in this project, the Brigham Palmer State #1 well, discovered 10.5 gross Bcfe of proved reserves, and is located on the flank of a potentially large Vicksburg field with gross unrisked reserve potential of over 50 Bcfe. In addition to this apparent field discovery, the Palmer State #1 provides a positive indication for a potentially large Vicksburg reservoir located on an adjacent fault block below the Mariposa Field. This field has produced over 86 Bcfe from the shallower Frio horizon; however, none of the existing wells have penetrated the deeper Vicksburg structure delineated from our 3-D survey. Thus, our Diablo Project has a number of exciting development and exploratory prospects that could have a significant impact on our Company's reserve and cash flow growth in 1999.

In 1999, we believe our Company and our shareholders will benefit from a number of factors:

First, we enter 1999 with a determination to realize value from our broad inventory of identified 3-D prospects. Benefiting from our active project assemblage and prospect capture efforts during the last several years, we are devoting substantially all of our resources and efforts to drilling in 1999, thereby maximizing our reserve value generated per expenditure.

Second, we are intently focused on maximizing the returns on our investments, both past and present. Our 1999 drilling program will be extremely disciplined and very much high-graded, and it will be focused in those plays and on those projects, such as Diablo and Southwest Danbury, where we have enjoyed good results to date. All our planned drilling activity will be in our Anadarko Basin and Gulf Coast core provinces, where we have achieved lower drilling costs and have attractive opportunities to rapidly and profitably grow reserves and production. In addition, we have hardly begun to drill within our record 968 net square miles of 3-D seismic acquired in 1998. Ongoing interpretation of this data should yield further drilling opportunities in our core focus areas.

Third, we will seek to access additional capital to fund the drilling of our high-graded prospect inventory. We are confident that we have captured substantial value within our vast portfolio of 3-D seismic projects. Improved liquidity will enable our Company to accelerate the monetization of our 3-D seismic investments by advancing the drilling stage of these projects, which should generate tangible value in the form of reserves and cash flow to improve our overall capital structure. Thus far in 1999, we have already made progress in this regard through the sales of interests in certain 3-D seismic projects, raising $11.5 million in capital to fund our activity.

Fourth, we will pursue creative opportunities to grow our Company in the current industry environment. The costs for drilling services are significantly lower than in 1998, in many areas by as much as 30% to 40%. This reduced cost environment provides an enviable window of opportunity for a prospect-rich company to drill. We are seeking to establish strategic alliances with industry service providers that will enable our Company and our business partners to leverage our respective resources and assets.

Lastly, our Company and our employees are determined to make the sacrifices necessary to insure our success, even in a difficult environment. We have implemented a number of measures to reduce our overhead costs, including a Company-wide salary reduction and the elimination or reduction of discretionary administrative costs. We will continue to optimize our personnel and allocate our resources to improve efficiency and the execution of our business plan.

In CLOSING, Brigham was founded on the basis of several core principles – innovation, creativity and honesty. We were determined to apply a new technology and new approach to a conventional industry. It is precisely these basic tenets that have driven our Company's rapid growth during the last eight years. In 1999, we will continue to employ these principles throughout all phases of our business to build upon our successes and increase value for our shareholders.

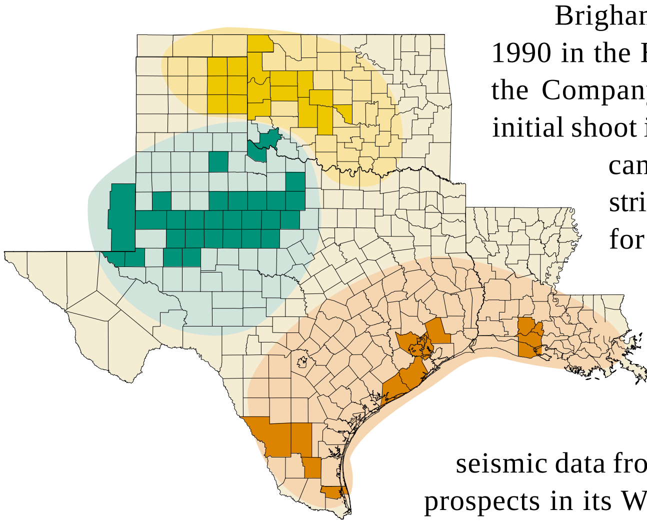
The challenges we faced in 1998 have taught us important lessons about the need for focus and continuous improvement in the execution of our growth strategy. We are optimistic that we can benefit from these experiences to improve our Company's profitability in our dynamic industry.

Our Company has amassed the building blocks necessary to generate substantial tangible value for its shareholders – a vast, high-quality 3-D prospect inventory, a highly skilled and proven staff of explorationists and an innovative, opportunistic business philosophy. We will work diligently to leverage these outstanding assets to deliver improved profitability and value creation for our Company in 1999.

Most importantly, I sincerely thank our employees and business partners for all of their hard work, dedication and contributions to the execution of our long-term growth strategy. I also would like to express my gratitude to my fellow shareholders for their continued support of Brigham Exploration Company.

Ben M. Brigham
Chairman of the Board
President and Chief Executive Officer
March 26, 1999

Areas of Operation



Brigham's first 3-D program was acquired late in 1990 in the Horseshoe Atoll trend of West Texas, and the Company drilled its first 3-D discovery on that initial shoot in March 1991. The discovery was significant in that it began a fairly remarkable early string of eight consecutive drilling completions for the year, and by early 1992 Brigham had completed 13 of its first 14 wells drilled. This early success validated the technology and the Company's innovative business model. As a result, Brigham aggressively acquired 3-D seismic data from 1992 to 1995, primarily focusing on oil prospects in its West Texas core province.

One of the key 3-D projects acquired outside of West Texas early in Brigham's history was a 13 square mile program acquired in the Anadarko Basin in 1991. Several additional Anadarko Basin projects were initiated in subsequent years, and in 1995 Brigham began to accelerate its 3-D activity in this prolific, relatively long-lived natural gas producing province. The Anadarko Basin became central to the Company's goal of accelerating its growth rate by focusing on larger reserve and production rate prospects. To complement these growth objectives, Brigham also initiated its 3-D exploration program in the onshore Gulf Coast province in 1995, recognizing this region's potential to generate even higher per well reserve and production rates through 3-D seismic-based drilling.

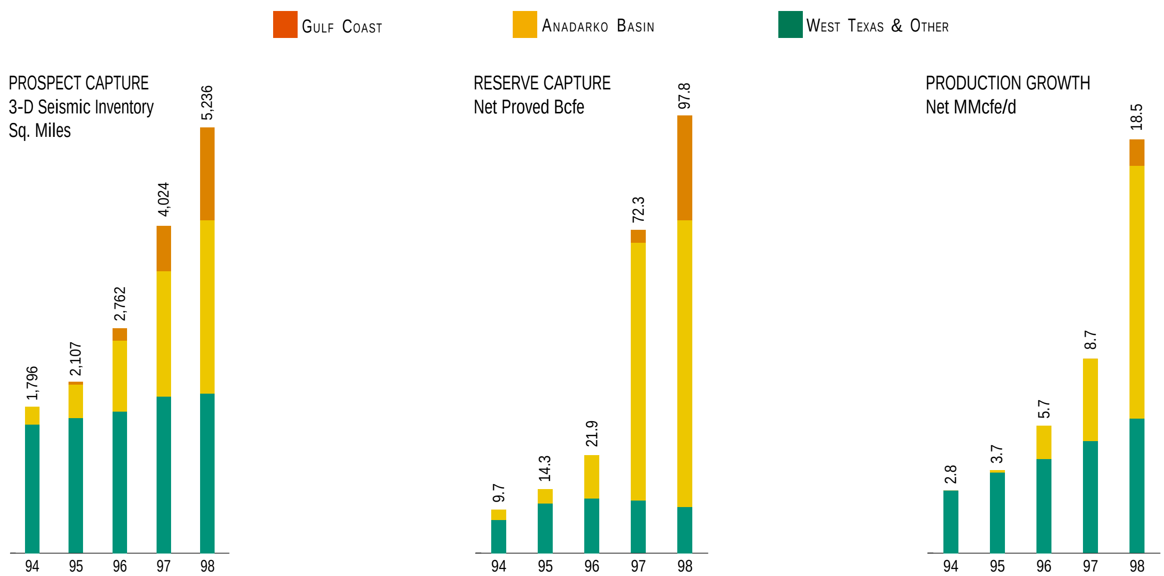
As of December 31, 1998	Anadarko Basin	Gulf Coast	West Texas & Other	Total
Gross Sq. Miles 3-D Seismic	2,124	1,148	1,964	5,236
Average Project WI	57%	75%	27%	49%
Gross Leased Acreage	143,298	24,341	74,019	241,658
% Undeveloped	81%	96%	90%	86%
Gross Optioned Acreage	73,175	96,319	4,176	173,670
Gross Wells Drilled	95	32	315	442
Average Drilling WI	38%	40%	25%	29%
Success Rate	75%	78%	59%	64%
Net Proved Reserves (Bcfe)	64.0	23.5	10.3	97.8
% Natural Gas	82%	70%	19%	73%
Est. Potential Drilling Locations	430	120	150	700

Brigham has made significant investments in 3-D seismic and prospective acreage in its Anadarko Basin and Gulf Coast provinces during the past three years. Through these investments, the Company believes it has assembled a sizeable inventory of potential 3-D delineated drilling locations to support a multi-year drilling program, thereby providing attractive opportunities to generate long-term growth. Based upon the interpreted portion of its

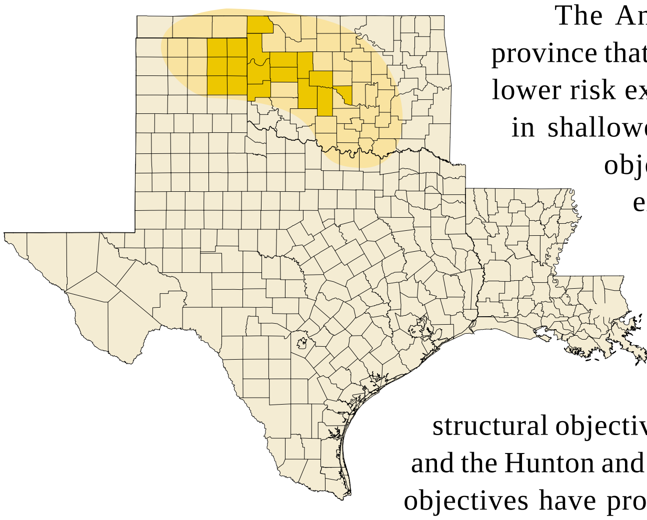
3-D seismic data at year-end 1998, the Company estimates that it has identified approximately 700 potential undrilled locations within its three core exploration provinces. From inception in 1990 through 1998, Brigham has achieved net drilling costs of $0.82 per Mcfe added through its 3-D seismic exploration efforts. More importantly, over 500 of Brigham's estimated potential drilling locations are in its currently active Anadarko Basin and Gulf Coast provinces where the Company has achieved inception-to-date net drilling costs of $0.68 and $0.59 per Mcfe, respectively. In addition, Brigham estimates that approximately 800 square miles of its 1,213 total square miles of 3-D seismic data acquired in 1998 had either not been interpreted or only partially interpreted at year-end 1998. Further interpretation of the recently acquired data should provide incremental potential drilling locations to fuel future growth.

Brigham intends to devote substantially all of its exploration efforts and available capital resources in 1999 to the drilling and monetization of its highest grade prospects in inventory. The Company's current 1999 capital budget is estimated to be $17.5 million, which represents a significant reduction from 1998 expenditures and its previously anticipated 1999 levels in an effort to match Brigham's current and expected future capital resources. The Company's budgeted 1999 capital expenditures consist of approximately $10 million to drill an estimated 20 to 25 gross wells, $3.5 million for seismic and land costs (primarily prior year commitments and obligations to acquire 3-D data and acreage), and $4 million for capitalized general and administrative expenses and other fixed asset expenditures. Brigham expects that its 1999 drilling expenditures will be allocated approximately 50% to its Anadarko Basin and 50% to its Gulf Coast province, and such expenditures will be concentrated within trends where the Company has experienced exploration success to date.

The Company's actual capital expenditures in 1999 may increase or decrease significantly from these estimates based upon capital availability during the year. Management believes Brigham has an attractive opportunity to profitably drill its highest grade 3-D delineated locations due to its historical drilling efficiency and the current low cost drilling environment. Therefore, one of the Company's goals in 1999 is to access additional capital to further monetize its prospect inventory.



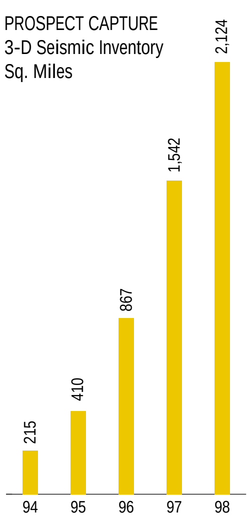
Anadarko Basin Province

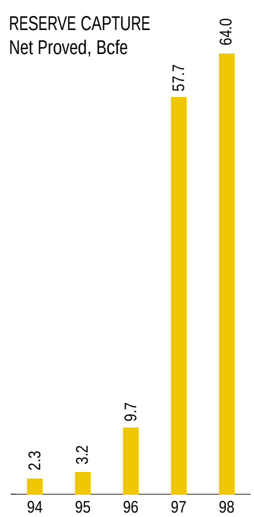


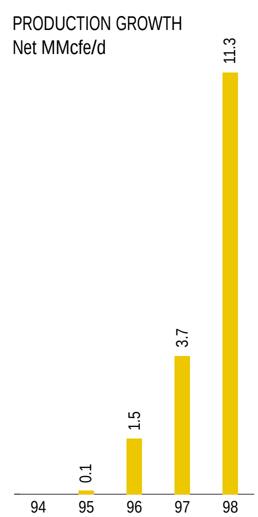
The Anadarko Basin is a prolific natural gas province that Brigham believes offers a combination of lower risk exploration and development opportunities in shallower horizons and deeper, higher potential objectives that have been relatively under explored. This province has produced in excess of 90 Tcfe to date from numerous, historically elusive stratigraphic targets, such as the Red Fork, Upper Morrow and Springer channel sands, as well as from deeper, higher potential structural objectives, such as the Lower Morrow sandstones and the Hunton and Arbuckle carbonates. In some cases, these objectives have produced in excess of 30 Bcf of natural gas from a single well at rates of up to 30 MMcf of natural gas per day. In addition, drilling economics in the Anadarko Basin are enhanced by the multi-pay nature of many of the prospects in this province, with secondary or tertiary targets serving as either incremental value or bailout potential relative to the primary target zone.

Following its initial 3-D seismic acquisition in this province in 1991 (12.5 square miles), Brigham acquired 51 square miles of 3-D seismic in 1993. Over the last several years the Company has accelerated its activity in the Anadarko Basin, acquiring 151 square miles of 3-D seismic in 1994, 195 square miles in 1995, 457 square miles in 1996, 675 square miles in 1997 and 583 square mile in 1998. Brigham retained a 75% average working interest in the 1,258 square miles of 3-D seismic data it acquired in this province in 1997 and 1998.

As of December 31, 1998, the Company had acquired 2,124 square miles in the Anadarko Basin covering 1.4 million acres, drilled 95 wells with a 75% success rate and discovered 48 net Bcfe at an average drilling cost of $0.68 per Mcfe. Year-end 1998 net proved reserves in







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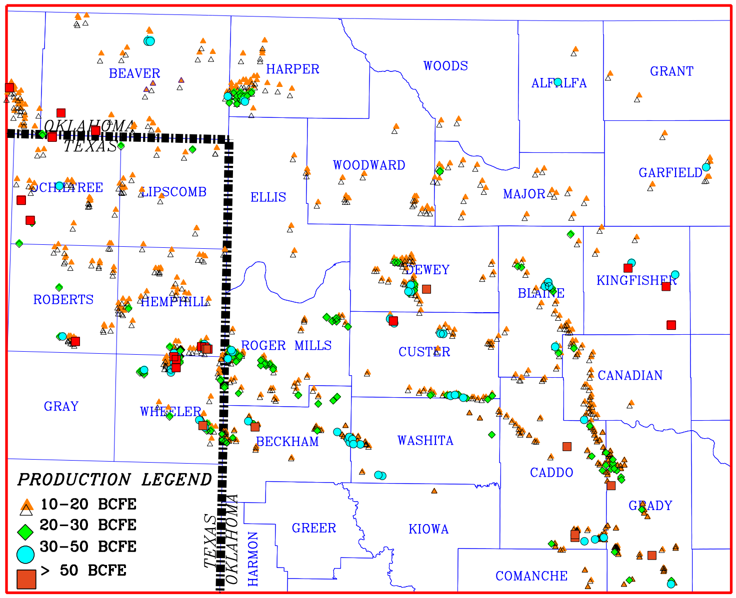
Anadarko Basin - 10 Bcfe or Greater Wells



this province total 64 Bcfe, representing 65% of Brigham's total proved reserve base. As of December 31, 1998, the Company had an estimated 430 3-D delineated potential drilling locations in the Anadarko Basin, of which Brigham intends to drill 10 to 15 gross wells in 1999 with an estimated average working interest of 40%. The Company does not currently intend to acquire additional 3-D seismic data in this province in 1999.

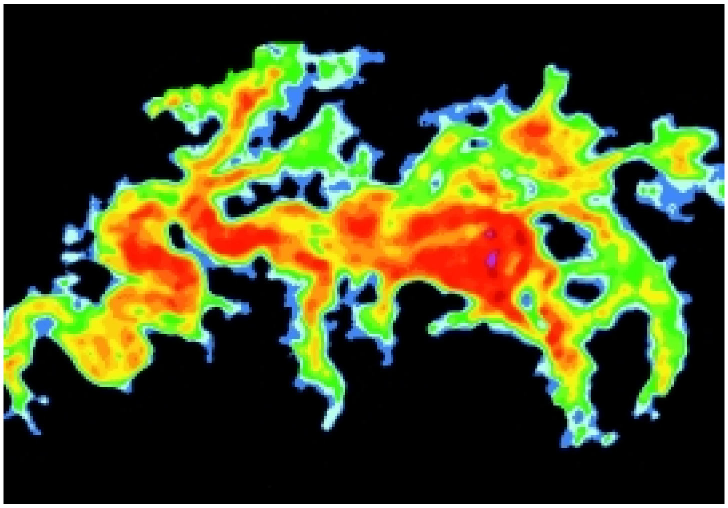
The following project highlights are indicative of Brigham's planned 1999 exploration activities in its Anadarko Basin province:

Gold Project

The Gold Project is located in Dewey and Blaine Counties, Oklahoma, and targets dual natural gas producing objectives in the Morrow sandstones and Hunton carbonates at depths of 9,500 to 11,500 feet. The initial acquisition of 89 square miles of 3-D seismic data covering the project acreage was completed in 1996 and drilling activity commenced in 1998 resulting in two Hunton discoveries. One of these discoveries, the Thomas #2 well (Brigham 34% working interest) found 2.4 gross Bcfe of proved reserves in the Hunton formation at a depth of 11,450 feet and was producing 2.5 MMcf of natural gas per day in mid-March 1999. The Thomas #2 is producing from a location which is believed to be associated with a potentially larger Hunton natural gas accumulation which could lead to several development locations. The Company and its participants have a number of additional Hunton and Morrow locations, mostly extensional and developmental in nature, planned for drilling in the Gold Project in 1999. Brigham has a 37.5% working interest in its Gold Project.

Huskie and Boilermaker Projects

Brigham's Huskie and Boilermaker Projects consist of 103 and 96 square miles, respectively, of continuous 3-D seismic data covering approximately 127,000 acres in Blaine County, Oklahoma. These projects target stratigraphic channel sands in the Springer with additional stratigraphic sand objectives in the Red Fork and Morrow in several identified prospects. Brigham initiated acquisition of data in its Huskie Project in 1996 where it retained a 37.5% working interest and, based upon the prospect density and reserve potential interpreted from this initial data set, the Company subsequently acquired data in its adjacent Boilermaker Project in 1998 where it retained a 100% working interest. The Company has

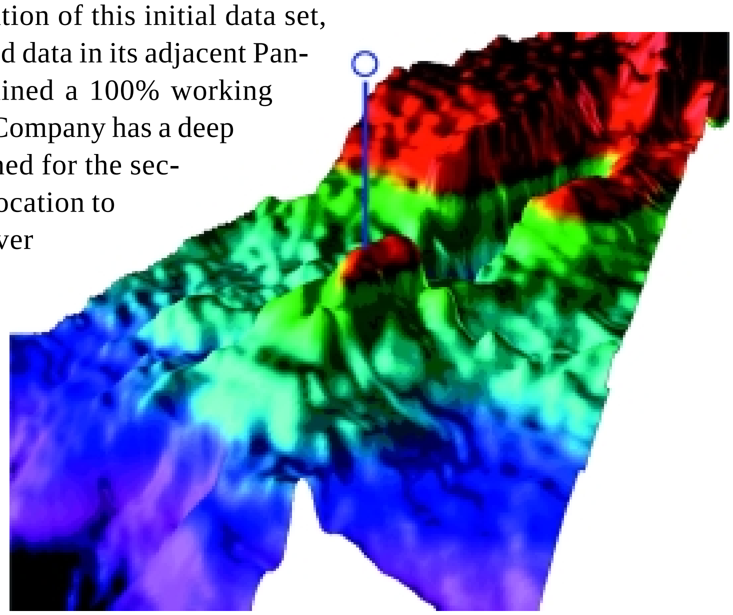


Three dimensional seismic amplitude image of a fluvial-deltaic channel system located within Brigham's Huskie and Boilermaker Projects. Analogous channel systems have produced significant natural gas reserves throughout portions of the Anadarko Basin.

been assembling acreage over a number of potential drilling locations in these project areas in 1998 and has at least one exploratory well planned for each project in 1999. An exploratory well planned for 1999 in the Huskie Project will test a prospect with greater than 15 Bcfe of gross unrisked potential which is an extension to a prolific Springer channel that has produced over 128 Bcfe of natural gas. Success from this initial exploratory well would likely establish several development locations.

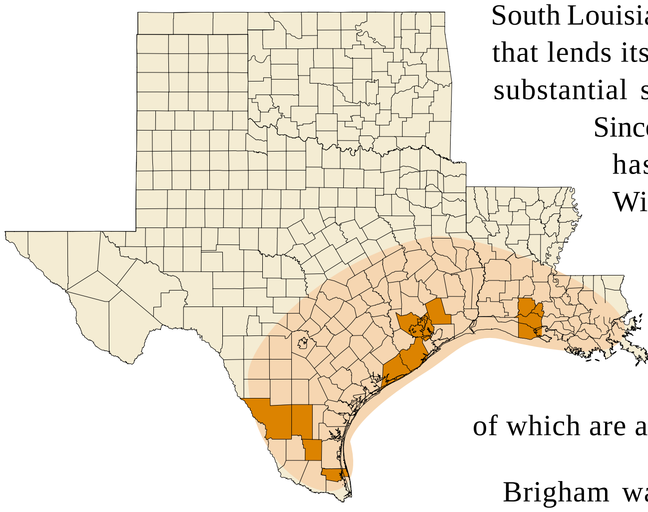
Wildcat and Panther Projects

The Company's Wildcat and Panther Projects consist of 50 and 99 square miles, respectively, of continuous 3-D seismic data covering approximately 95,000 acres in the southern portion of the Texas Panhandle in Wheeler County, Texas and Beckham County, Oklahoma. The primary exploration targets within these projects are high potential, structural features at depths ranging from 7,500 to 21,000 feet. Brigham initiated acquisition of data in its Wildcat Project in 1997 where it retained a 37.5% working interest. Based upon the interpretation of this initial data set, the Company subsequently acquired data in its adjacent Panther Project in 1998 where it retained a 100% working interest. In its Wildcat Project, the Company has a deep 21,000 foot exploratory well planned for the second half of 1999 to drill an updip location to a Hunton well that has produced over 14.5 Bcfe since 1981 and was still producing in mid-March 1999. The Company believes successful completion of this exploratory test could prove up an additional 27 Bcfe of remaining reserves in the attic of this producing structure. Also in 1999, the Company plans to drill a 7,500 foot test for 17 Bcfe of gross unrisked potential reserves in a dual objective Brown Dolomite/Granite Wash structure.



The proposed well symbol identifies the location of a 11,400' Lower Morrow well planned by Brigham in the Anadarko Basin during 1999. This well should evaluate a number of shallow prospective zones on its way to the primary target. The successful completion of this well would establish one direct offset location and high grade a number of other potential locations within this project.

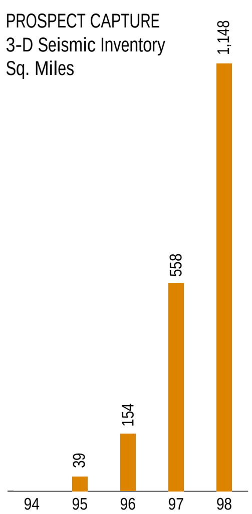
Gulf Coast Province

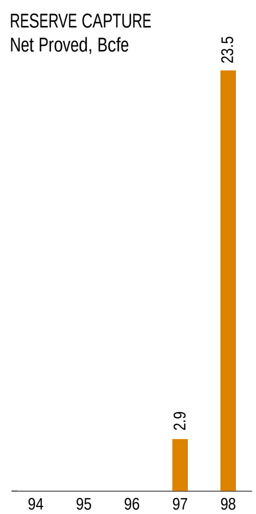


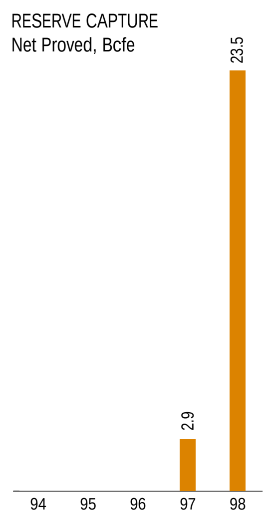
The onshore Gulf Coast region of Texas and South Louisiana is a high potential, multi-pay province that lends itself to 3-D seismic exploration due to its substantial structural and stratigraphic complexity. Since its entry into this region in 1995, Brigham has assembled projects in the Expanded Wilcox and Expanded Vicksburg trends in South Texas, the Miocene and Upper, Middle, and Lower Frio trends of the mid-to-southern regions of Texas, and the Lower Miocene trend in the transition zone of South Louisiana, each of which are active 3-D seismic exploration trends.

Brigham was attracted to the Gulf Coast province because of the opportunity to apply the Company's established 3-D seismic exploration approach and its staff's extensive Gulf Coast experience to a prolific, highly complex structural province with potential to discover significant natural gas reserves and production. The Company initiated its Gulf Coast effort in 1995 with the acquisition of 39 square miles of seismic data in its Esperson Dome Project in which the Company retained a small net profits interest that converts to variable back-in working interest of 12% to 20% upon project payout. Brigham's exploration efforts in its Esperson Dome Project to date have yielded the discovery of approximately 22 Bcfe of gross proved reserves from 11 wells, mostly from objectives above 6,000 feet, with a number of prospects still remaining to be drilled.

Over the last three years Brigham has accelerated its activity in the Gulf Coast, acquiring 115 square miles of 3-D seismic data in 1996, 404 square miles in 1997, and 590 square miles in 1998. The Company retained a 77% average working interest in the 1,109 square miles of 3-D seismic data it acquired in this province from 1996 through 1998. Brigham anticipates that its







increased project assemblage and 3-D seismic acquisition activity in the Gulf Coast will result in the allocation of a higher percentage of its drilling budget to this province in 1999, and will be a significant factor in the Company's future growth.

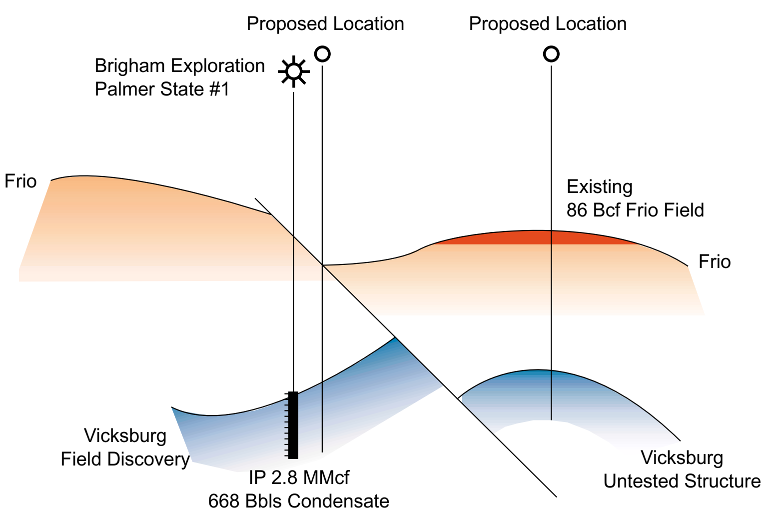
As of December 31, 1998, the Company had acquired 1,148 square miles in the Gulf Coast region covering 734,720 acres, drilled 32 wells with a 78% success rate and discovered 24 net Bcfe at an average drilling cost of $0.59 per Mcfe. Year-end 1998 net proved reserves in this province total 23.5 Bcfe, representing 24% of Brigham's total proved reserve base. As of December 31, 1998, the Company had an estimated 120 3-D delineated potential drilling locations in its Gulf Coast province, of which the Company intends to drill 10 gross wells in 1999 with an estimated average working interest of 55%. The Company does not currently intend to acquire additional 3-D seismic data in this province in 1999.

The following project highlights are indicative of Brigham's planned 1999 exploration activities in its Gulf Coast province:

Diablo Project

Brigham's Diablo Project covers approximately 57 square miles in Brooks County, Texas, and targets shallow Frio and deep Vicksburg producing horizons. The Company has entered into a venture with a major integrated oil company that controls adjoining acreage to explore on the combined acreage for potential below 10,000 feet in the Vicksburg formation. Brigham has retained a 34% working interest in this joint exploration project. However, in prospective zones above 10,000 feet, primarily the Frio, Brigham has retained a 100% working interest in its original 4,000 acre lease block. The Company and its participant control approximately 12,000 net acres of leasehold in the Diablo Project.

Diablo Project 3-D Based Schematic Cross Section



The gas well symbol illustrates the Brigham-operated Palmer State #1 discovery (33% WI) on the flank of an 800 acre Vicksburg structure. The Company believes this discovery may set up a number of potential updip offsets, one of which is shown. In 1999, Brigham and its major oil company participant also plan to drill the crest of an adjacent structure to test a large untested Vicksburg closure, directly below an 86 Bcfe Frio field, shown here in red.

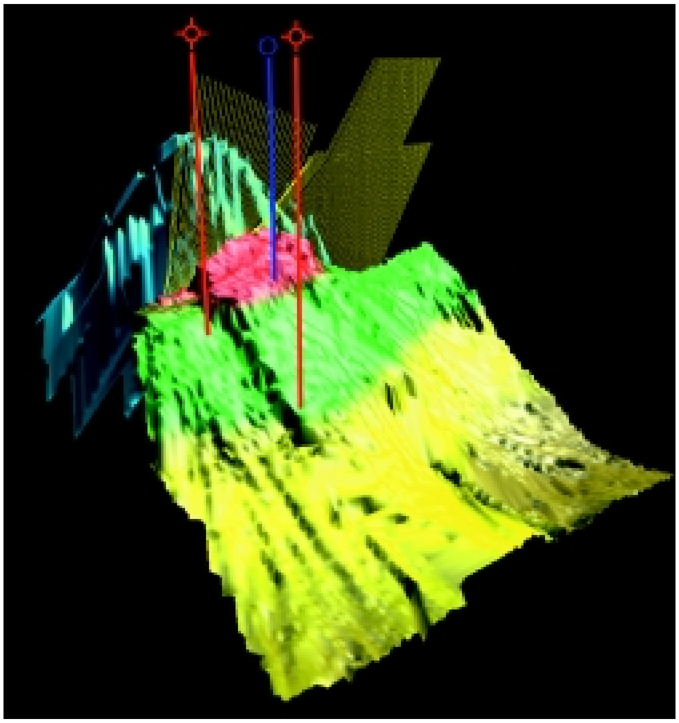
In the fourth quarter of 1998, Brigham made a potentially significant Lower Vicksburg discovery in its Diablo Project with the completion of the Brigham Palmer State #1 well (Brigham 33% working interest). The Palmer State #1 was successfully completed in three of five possible Lower Vicksburg pay zones at depths ranging from 9,600 to 12,800 feet and initially tested at a rate of 2.8 MMcf of natural gas and 668 Bbls of condensate per day. This discovery well appears to be located on the downdip flank of a structure which exceeds 800 acres in closure and contains potential gross unrisked reserves exceeding 50 Bcfe. A minimum of five potential development locations have been identified on the crest of the structure which are updip to the Palmer State #1 discovery well, the first of which is expected to spud late in the second or early in the third quarter of 1999. In addition, the Company has identified a large, downthrown, four-way closure in an adjacent fault block which has produced over 86 Bcfe from the shallower Frio formation, but which has not been tested in the equivalent Vicksburg sands that produce in the Company's Palmer State #1 well. Brigham plans to spud an exploratory well to test this high potential faulted closure in mid-1999.

Southwest Danbury Project

Located in Brazoria County, Texas, Brigham's Southwest Danbury Project is an approximate 29 square mile 3-D project targeting a series of pressured Lower Frio sands at depths ranging from 12,000 to 13,000 feet. In the first half of 1998, the Brigham Nold Gas Unit #1 (Brigham working interest 46%) was drilled to a depth of approximately 12,700 feet to test a Lower Frio amplitude, or bright spot, and encountered 29 feet of net pay. This well has produced at an average daily rate of 2.6 MMcf of natural gas with 17 Bbls of condensate and 13 Bbls of water since August 1998. Based on the results from this initial well, the Company spud the Brigham Renn Gas Unit #1 (Brigham working interest 83.5%) in late December 1998 to test another Lower Frio 3-D bright spot prospect with over 6 Bcfe of gross unrisked reserve potential. This well reached total depth and was in the process of completing in late March 1999. Brigham is also evaluating several additional Lower Frio prospects in its Southwest Danbury Project which could expose the Company to significant upside potential.

Hawkins Ranch Project

Brigham's Hawkins Ranch Project is a 160 square mile 3-D seismic program in the Miocene/Frio trend located in Matagorda County, Texas. This project targets potential in the shallow, nonpressured Miocene and Frio sands as well as the deeper, pressured Frio sands. In addition to the shallow Miocene potential, the Company has identified a number of prospects targeting deeper Frio objectives in its Hawkins Ranch Project. The first Lower Frio exploratory well should spud in the second half of 1999. This well is a 14,000 foot pressured test of a 500 acre structure with associated gross unrisked reserve potential exceeding 33 Bcfe. Brigham retains a 60% working interest in its Hawkins Ranch Project.



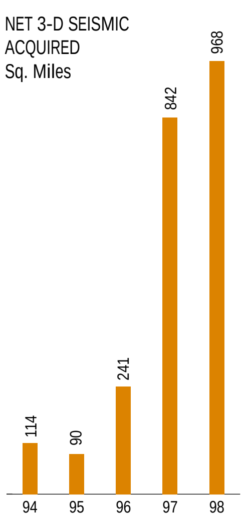
Lower Frio gas prospect. The downdip dry hole encountered a significant gas show while drilling and logged 16' of gas on water in a 82' gross sand interval. Due to completion problems, the well was plugged and abandoned. The updip dry hole crossed a fault and was wet. Brigham's location is approximately 250' updip from the updip dry hole. The potential trap covers approximately 500 acres, with estimated potential gross unrisked reserves of greater than 33 Bcfe. Adjacent salt dome is shown in blue.

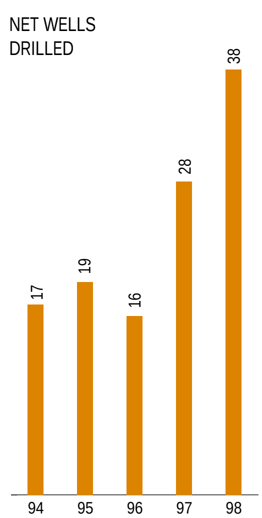
BRIGHAM Exploration Company

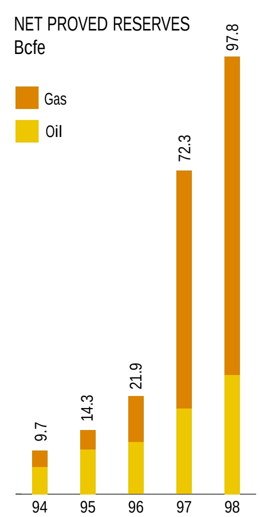
Operational & Financial Data

	Year Ended December 31					
	1994	1995	1996	1997	1998	CAGR [a]
3-D Seismic Acquired:						
Gross Square Miles	423	311	655	1,262	1,213	30%
Net Square Miles	114	90	241	842	968	71%
Average Project Working Interest	27%	29%	37%	67%	80%	31%
Wells Drilled:						
Gross Wells	73	78	67	73	72	0%
Net Wells	16.8	18.5	15.9	28.3	37.6	22%
Average Drilling Working Interest	23%	24%	24%	39%	52%	23%
Net Proved Reserves (at year end):						
Natural Gas (MMcf)	3,579	4,257	10,257	53,230	71,166	111%
Oil (MBbls)	1,022	1,672	1,940	3,181	4,433	44%
Natural Gas Equivalents (MMcfe)	9,711	14,289	21,897	72,316	97,764	78%
Percent Natural Gas	37%	30%	47%	74%	73%	
Percent Proved Developed	76%	80%	67%	65%	57%	
SEC PV10% (at year end):						
Before Income Taxes ($000)	$10,240	$18,222	$44,506	$69,249	$81,741	68%
After Income Taxes ($000)	$10,240	$18,222	$44,506	$64,274	81,649	68%
Net Proved Reserve Additions[b]:						
All Sources (MMcfe)	8,473	6,001	11,599	53,587	32,093	40%
Excluding Acquisitions (MMcfe)	8,473	6,001	11,321	32,405	31,176	38%
Reserve Replacement Ratio[c]:						
All Sources	846%	451%	563%	1,714%	483%	
Excluding Acquisitions	846%	451%	550%	1,037%	469%	
Net Production Volumes:						
Natural Gas (MMcf)	165	272	698	1,382	4,269	126%
Oil (MBbls)	140	177	227	291	396	30%
Natural Gas Equivalents (MMcfe)	1,002	1,332	2,060	3,126	6,644	60%
Percent Natural Gas	16%	20%	34%	44%	64%	
Average Sales Prices:						
Natural Gas ($/Mcf)	$1.76	$1.62	$2.30	$2.56	$2.04	
Oil ($/Bbl)	$16.30	$17.76	$19.98	$19.40	$12.85	

(a) Compound annual growth rate, 1994-1998.
(b) Includes net revisions to previous estimates in the period incurred.
(c) Net proved reserve additions divided by net production volumes for the period.

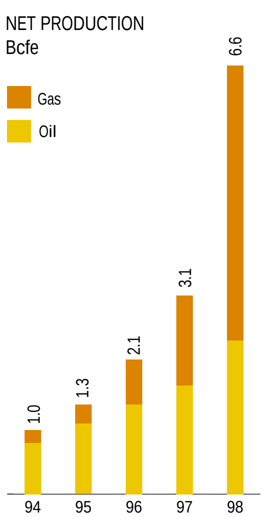


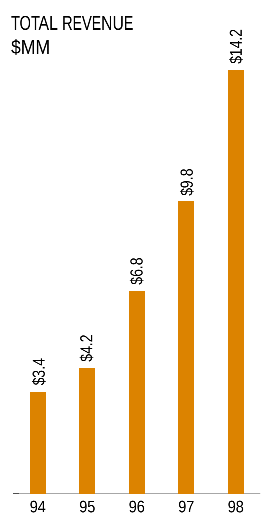


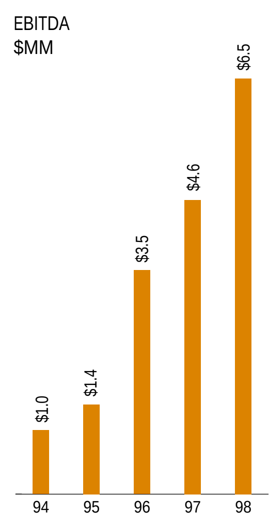


($ in thousands, except per share and per Mfce data)	Year Ended December 31				
	1994	1995	1996	1997	1998
Operating Results:					
Natural Gas and Oil Sales	$2,565	$3,578	$6,141	$9,184	$13,799
Total Revenue	3,380	4,213	6,768	9,821	14,189
EBITDA [(a)]	978	1,390	3,481	4,551	6,495
Operating Cash Flow [(b)]	366	582	2,360	3,506	1,030
Net Loss	(1,299)	(1,577)	(450)	(1,117) [(c)]	(33,345) [(d)]
Per Diluted Share Data:					
Net Loss Per Share	($0.15)	($0.18)	($0.05)	($0.10) [(c)]	($2.64) [(d)]
Operating Cash Flow Per Share	$0.04	$0.07	$0.26	$0.31	$0.08
Wt. Avg. Shares Outstanding:					
Basic (000)	8,929	8,929	8,929	11,081	12,626
Diluted (000)	8,929	8,929	8,929	11,198	12,832
Capital Expenditure Data:					
Net Seismic and Land	($770)	$667	$6,066	$22,881	$40,783
Net Drilling	4,720	5,888	6,047	19,191	36,857
Property Acquisitions	--	--	--	13,500	1,021
Capitalized G&A	1,320	1,640	1,826	3,460	4,619
Total Costs Incurred	$5,270	$8,195	$13,939	$59,032	$83,280
Balance Sheet Data:					
Cash and Cash Equivalents	$700	$1,802	$1,447	$1,701	$2,569
Net Natural Gas and Oil Properties	11,970	18,538	28,005	84,294	134,317
Total Assets	15,781	22,916	33,614	92,519	150,516
Total Debt	7,950	16,000	24,000	32,000	94,786
Total Equity	5,271	3,694	3,244	43,313	24,681
Per Mcfe Data:					
Natural Gas and Oil Sales	$2.56	$2.69	$2.98	$2.94	$2.08
Workstation Revenue	0.81	0.47	0.31	0.20	0.06
Total Revenue	3.37	3.16	3.29	3.14	2.14
Lease Operating Expenses	0.49	0.57	0.35	0.37	0.33
Production Taxes	0.13	0.12	0.18	0.18	0.13
Net G&A Expenses	1.78	1.42	1.07	1.14	0.70
EBITDA	$0.97	$1.05	$1.69	$1.45	$0.98

(a) EBITDA represents net income (loss) plus income taxes, net interest expense and depreciation, depletion and amortization expenses.
(b) Operating cash flow represents net income (loss) plus DD&A expenses, deferred income taxes and other non-cash items.
(c) Includes a net $1.2 million ($0.10 per diluted share) non-cash deferred income tax charge related to the Company's conversion from a partnership to a corporation in 1997.
(d) Includes a $24.8 million ($1.97 per diluted share) non-cash capitalized ceiling impairment charge in 1998.







BRIGHAM
Exploration Company

Officers & Directors

BEN "BUD" M. BRIGHAM	President, Chief Executive Officer and Chairman of the Board
JON L. GLASS	Vice President - Exploration and Director
CRAIG M. FLEMING	Chief Financial Officer
DAVID T. BRIGHAM	Vice President - Land and Administration, Corporate Secretary
A. LANCE LANGFORD	Vice President - Operations
KAREN E. LYNCH	Vice President - Legal and General Counsel
ANNE L. BRIGHAM	Director *Former Executive Vice President of* *Brigham Exploration Company*
HAROLD D. CARTER	Director and Consultant *Former President and Chief Operating* *Officer of Sabine Corporation*
W. CRAIG CHILDERS	Director *Head of Producer Finance and Services Group of* *Enron Capital & Trade Resources Corp.*
ALEXIS M. CRANBERG	Director *President of Aspect Management Corporation* *Director of Coherence Technology Company* *Director of Westport Oil & Gas Company*
STEPHEN P. REYNOLDS	Director *Managing Member of General Atlantic Partners, LLC*

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 the Company's filings with the Securities and Exchange Commission.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 1998
OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ____________________ to ____________________

Commission file number:

BRIGHAM EXPLORATION COMPANY

(Exact name of Registrant as Specified in its Charter)

Delaware (State or other jurisdiction of incorporation or organization)	**75-2692967** (I.R.S. Employer Identification No.)
6300 Bridge Point Parkway **Building 2, Suite 500** **Austin, Texas** (Address of principal executive offices)	**78730** (Zip Code)

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

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

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

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

Common Stock, $.01 par value
(Title of Class)

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

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

As of March 26, 1999, the Registrant had outstanding 13,306,206 shares of Common Stock. The aggregate market value of the Common Stock held by non-affiliates of the Registrant, based upon the closing sale price of the Common Stock on March 26, 1999, as reported on The Nasdaq Stock MarketK, was approximately $18 million.

Pursuant to Rule 12b-25 under the Act, (1) combined financial statements of the Registrant's subsidiaries whose securities are pledged as collateral for the Registrant's Senior Subordinated Secured Notes and (2) certain exhibits have been omitted from this Form 10-K.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the Registrant's 1999 Annual Meeting of Stockholders to be held on May 13, 1999, 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, 1998.

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BRIGHAM EXPLORATION COMPANY

1998 ANNUAL REPORT ON FORM 10-K

PART I

ITEM 1. BUSINESS

Overview

Brigham Exploration Company ("Brigham" or the "Company") is an independent exploration and production company that applies 3-D seismic imaging and other advanced technologies to systematically explore and develop onshore oil and natural gas provinces in the United States. The Company focuses its 3-D seismic activity in provinces where it believes 3-D technology may be effectively applied to generate relatively large potential reserve volumes per well and per field, high potential production rates and multiple producing objectives. The Company's exploration activities are concentrated primarily in three core provinces: the Anadarko Basin of western Oklahoma and the Texas Panhandle; the onshore Gulf Coast of south Texas and, to a lesser extent, the transition zone of Louisiana; and West Texas.

The Company pioneered the acquisition of large scale onshore 3-D seismic surveys for exploration, obtaining extensive 3-D seismic data and experience in capturing undiscovered oil and natural gas reserves. As of December 31, 1998, Brigham has acquired 5,236 square miles (3.3 million acres) of 3-D seismic data and has identified an estimated 1,140 potential drilling locations, of which the Company has drilled 442. The Company generates most of its exploratory projects and, therefore, has the ability to retain a sizeable working interest to the extent that it decides not to place interests with industry participants.

From inception in 1990 through 1998, Brigham has drilled 378 exploratory and 64 development wells on its 3-D generated prospects with an aggregate 64% success rate and an average working interest of 29%. As of December 31, 1998, the Company has added 114 Bcfe of net proved reserves to its reserve base, approximately 92 net Bcfe of which were discovered by Brigham through its systematic 3-D exploration drilling activities at an average net drilling cost of $0.82 per Mcfe. The Company's estimated net proved reserves as of December 31, 1998 were 97.8 Bcfe having an aggregate Present Value of Future Net Revenues of $81.7 million, compared to estimated net proved reserves as of December 31, 1996 of 21.9 Bcfe having an aggregate Present Value of Future Net Revenues of $44.5 million. The Company's net proved reserve volumes at December 31, 1998 are 73% natural gas and 57% proved developed reserves.

Business Strategy

Brigham's principal objective and business strategy is to achieve superior growth in shareholder value through the application of its systematic exploration approach, which emphasizes the integrated use of 3-D seismic imaging and other advanced technologies to reduce drilling risks and finding costs. Since its inception in 1990, the Company has achieved rapid growth in its acquisition of 3-D seismic data, identification of potential drilling locations, discovery of proved reserves and production volumes.

Brigham completed its initial public offering of common stock in May 1997, raising approximately $24 million to fund the Company's accelerated 3-D seismic acquisition and exploration drilling activities. Key elements of the Company's long-term growth strategy at its initial public offering and continuing today include: (i) acquiring 3-D seismic data in proven producing trends to identify and capture potential drilling locations; (ii) retaining significant working interests in its exploration projects to capture a greater share of the reserves that the Company discovers; (iii) identifying higher potential, higher impact prospects; and (iv) monetizing the value of its 3-D seismic investments by drilling its inventory of 3-D seismic delineated locations.

Since its initial public offering in early 1997, Brigham has been effective in the implementation of its long-term growth strategy. During 1997 and 1998, the Company acquired 2,475 square miles of 3-D seismic data at an average working interest of 73%, which nearly doubled its inventory of gross onshore 3-D seismic data to 5,236 square miles as compared to year-end 1996 and increased its net onshore 3-D seismic data in inventory more than three-fold from 780 square miles at year-end 1996 to 2,590 square miles at year-end 1998. Brigham's overall level of 3-D seismic acquisition during the past two years represents the most active in the Company's history, and 90% of the recently acquired data is located in Brigham's higher potential Anadarko Basin and Gulf Coast provinces where it has achieved historically lower finding costs for drilling than in its West Texas province. As a result of these significant investments in 3-D seismic acquisition and interpretation in proven natural gas producing trends, the Company believes it has assembled a significant competitive knowledge base and strategic position in each of its two active exploration provinces. Brigham further believes it has captured a high quality inventory of 3-D delineated potential drilling locations that can be monetized through the drillbit at profitable finding costs over the next several years, thereby providing opportunities for future reserve, production and cash flow growth.

Brigham has substantially reduced its planned capital expenditure budget for 1999 and has undertaken a number of strategic initiatives in an effort to improve and preserve its capital liquidity in the current environment. While the Company remains focused on its long-term growth objectives and the continuation of its established business model for 3-D seismic-based exploration, Brigham has adapted its business strategy in the near-term in an effort to maximize value for its shareholders on a long-term basis through the implementation of the following principal strategic initiatives: (i) focusing all of the Company's planned exploration efforts in 1999 toward the drilling of its highest-grade 3-D prospects identified in its Anadarko Basin and Gulf Coast projects, concentrated primarily in trends where Brigham has achieved exploration success, (ii) eliminating substantially all planned seismic and land expenditures for new projects until its capital resources can support such additional activity, (iii) seeking to divest certain producing natural gas and oil properties in an effort to raise capital to reduce debt borrowings and to redirect capital to drilling projects that have the potential to generate higher investment returns, (iv) restructuring its outstanding senior and subordinated debt agreements to provide the Company with flexibility needed to preserve cash flow to fund its expected near-term exploration activities, (v) implementing an overhead reduction plan to reduce general and administrative expenses, and (vi) evaluating opportunities to raise additional equity capital either through the sales of interests in certain of its seismic projects or the issuance of equity securities. The Company believes that the successful execution of these strategic initiatives will provide Brigham with sufficient capital resources to execute its planned 1999 exploration program and position the Company to realize the significant value it believes it has captured in its inventory of 3-D seismic projects and delineated drilling locations. See "Item 7. Management's Discussion and Analysis of Financial Condition and Operating Results — Liquidity" and "— Capital Resources."

Exploration and Operating Approach

The Company has acquired 3-D seismic data covering 5,236 square miles (3.3 million acres) in over 20 geologic trends in seven basins and seven states. Through this activity, the Company has developed expertise in the selection of geologic trends that are suitable for 3-D seismic exploration. Brigham uses experience that it gains within a trend to enhance the quality of subsequent projects in the same trend and other analogous trends, contributing to lower finding and development costs, compressed project cycle times and increased project rates of return.

The Company typically acquires 3-D seismic data in and around existing production where the Company can benefit from the imaging of producing analogs. These 3-D defined analogs, combined with the Company's experience in drilling 442 wells, provide the Company with a knowledge base to evaluate other potential geologic trends, 3-D seismic projects within trends and 3-D delineated potential drilling locations. The Company's knowledge base assists in identifying geologic trends where Brigham believes it can find and develop economic volumes of oil and natural gas.

The Company has experience exploring with 3-D seismic in a wide range of reservoir types and geologic trapping styles, both stratigraphic and structural (including reefs, salt domes, channel sands, complex faulted and fractured reservoirs and pinchout plays). The Company seeks to supplement its knowledge base with the best local geologic expertise available for a particular geologic trend. In addition, the Company typically acquires digital data bases for integration on the Company's CAEX workstations, including digital land grids, well information, log curves, production information, geologic studies, geologic top data bases and existing 2-D seismic data.

The Company uses its knowledge base, local geological expertise and digital data bases integrated with 3-D seismic to create maps of producing and potentially productive reservoirs. The Company believes its 3-D generated maps are more accurate than previous reservoir maps (which generally were based on subsurface geological information and 2-D seismic surveys), enabling the Company to more precisely evaluate recoverable reserves and the economic feasibility of projects and drilling locations.

Brigham acquires most of its raw 3-D seismic data using seismic acquisition vendors on either a proprietary basis or through alliances affording it the exclusive right to interpret and use data for extended periods of time. In addition, the Company participates in non-proprietary group shoots of 3-D data when it believes the expected full cycle project economics are justified. In its proprietary acquisitions and alliances, Brigham selects the sites of projects, primarily guided by its knowledge and experience in the core provinces it explores; establishes and monitors the seismic parameters of each project for which data is shot; and typically selects the equipment that will be used. Data is generally priced on the basis of square miles shot. See “Item 1. Business — Industry Alliances.”

Exploration Staff

Over the last eight years the Company has assembled an exploration staff that includes ten geophysicists, ten geologists, four petroleum engineers, five computer applications specialists, five geophysical/geological/engineering technicians, six landmen and six lease and division order analysts. Brigham’s ten 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), provide the Company with valuable technical intellectual resources. The Company’s team of explorationists has over 310 years of exploration experience and more than 85 years of 3-D CAEX workstation experience, most of which was acquired at Brigham and various major and large independent oil companies. Occasionally, the Company complements and leverages its exploration staff by seeking out alliances or retainer relationships with geologists having extensive experience in a particular area of interest.

3-D Seismic Technology

The Company’s strategy is to use 3-D seismic and other advanced technologies, including CAEX, to systematically explore and develop domestic onshore oil and natural gas provinces. In general, 3-D seismic is the process of acquiring seismic data along multiple lines and grids. The primary advantage of 3-D seismic over 2-D seismic is that it provides information with respect to multiple horizontal and vertical points within a geologic formation instead of information on a single vertical line or multiple vertical lines within the formation. Acquiring larger amounts of data relating to a geologic formation allows a user to better correlate the data and, in some cases, obtain a greater understanding and image of the formation. Although it is impossible to predict with certainty the specific configuration or composition of any underground geologic formation, the use of 3-D seismic data provides clearer and more accurate projected images of complex geologic formations, which can assist a user in evaluating whether to drill for oil and natural gas reserves. If a decision to drill is made, 3-D seismic data can also help in determining the optimal location to drill.

CAEX is the process of accumulating and analyzing the various seismic, production and other data obtained relating to a geographic area. In general, CAEX involves accumulating various 2-D and 3-D seismic data with respect to a potential drilling location, correlating that data with historical well control and production data from similar properties and analyzing the available data through computer programs and modeling techniques to project the likely geologic composition of a potential drilling location and potential locations of undiscovered oil and natural gas reserves. This process relies on a comparison of data with respect to the potential drilling location and historical data with respect to the density and sonic characteristics of different types of rock formations, hydrocarbons and other subsurface minerals, resulting in a projected three dimensional image of the subsurface. This modeling is performed through the use of advanced interactive computer workstations and various combinations of available computer programs that have been developed solely for this application.

Brigham has invested extensively in the advanced computer hardware and software necessary for 3-D seismic exploration. The Company has both Landmark and Geoquest CAEX workstations. This workstation flexibility provides the Company the opportunity to interpret a project on the particular CAEX workstation that it believes is best suited for defining those particular geologic objectives. Brigham's explorationists can access a diverse software tool kit including SeisWorks, StratWorks, EarthCube, OpenVision, Open Explorer, ZAP, Zmap+, ARIES, SynTool, Poststack, TDQ, AutoPix, MapView, GeoViz, Voxels, SynView, CSA (Computed Seismic Attributes), Surface Slice, Hampson — Russell AVO Analysis and Modeling and ZEH Graphics CGMage Builder (graphics montage tool).

The Company believes that its use of 3-D seismic technology provides it with a number of benefits in the exploration, delineation and development process that are not generally available to those who only use 2-D seismic data and conventional processing methods. In particular, the Company believes that it obtains clearer and more accurate projected images of underground formations through computer modeling, and is therefore better able to identify potential locations of hydrocarbon accumulations based on the characteristics of the formations and analogies made with nearby fields and formations where hydrocarbons have been found. This enhanced data has been used to assist the Company in eliminating potential drilling locations that might otherwise have been drilled had the Company relied solely on 2-D seismic data. This data has also been used to assist the Company in attempting to identify the most desirable location for the wellbore to increase the prospects of a successful exploratory or development well and production from the reservoir.

Industry Alliances

Veritas Anadarko Basin Acquisition Alliances. Pursuant to certain alliances with Veritas DGC Land Ltd. ("Veritas"), Brigham has acquired approximately 1,460 square miles of 3-D seismic in the Anadarko Basin through December 31, 1998 and has agreed to acquire from 165 to 265 additional square miles of data to be divided among individual projects in that province. In exchange for the Company's commitment to Veritas, the Company and its assignees only pay a portion of the 3-D seismic acquisition costs as the data is acquired. As the Company leases acreage or drills wells, it pays Veritas the balance of the deferred costs in the form of leasing and drilling fees until such deferred costs are repaid or until certain time periods have occurred. In addition, in the event that the outstanding balance of deferred seismic acquisition costs exceeds certain threshold amounts, the Company must pre-pay part of the leasing and drilling fees to cause the outstanding balance to fall below the current threshold amount. These arrangements afford the Company access to 3-D seismic acquisition in a compressed cycle time, providing the Company with significant operational efficiencies.

In addition, Veritas Geoservices, Ltd. provides employees that maintain and operate seismic data processing workstations in Brigham's offices. Supervised by Brigham's geophysicists, the vendor's employees process most of the Company's 3-D seismic. The associated improvement in communication and integration, from field data acquisition to processing, reduces project cycle times, and therefore costs, while improving the quality of the data for Brigham's subsequent interpretation.

Anadarko Basin Alliance I. The Company has entered into alliances with Vintage Petroleum, Inc. ("Vintage") and Stephens Production Company ("Stephens") which provided for their participation with Brigham in all of the projects that the Company conducted within a 625 square mile 3-D seismic program that was completed in 1997 with Veritas in the Anadarko Basin. Vintage and Stephens incurred a disproportionate share of all pre-seismic and certain seismic costs on all projects in the program. Net of the interests of Vintage and Stephens, the Company holds a 37.5% interest in the program. The Company believes that this leveraging of its costs was possible because of the expertise and knowledge that the Company has developed, enabling the Company to build its revenue and cash flow base at a time when it has been capital constrained.

Anadarko Basin Alliance II. Upon completion of data acquisition in its Alliance I program, Brigham began acquiring 3-D seismic under a second alliance with Veritas in the Anadarko Basin. From August 1997 through November 1998, the Company acquired approximately 835 square miles of 3-D seismic under this alliance with a 100% working interest. Pursuant to the terms of its acquisition agreement with Veritas, Brigham ceased acquisition of 3-D seismic data in the Alliance II program in early November 1998, and the Company will consider acquiring the balance of the data contemplated in this program when it determines that its capital resources are sufficient to incur such expenditures. The Company currently intends to retain a majority working interest in its Alliance II seismic projects subsequent to the sale and potential future sales of a portion of its working interests in certain of these projects. See "— Duke Project Financing."

Carry-to-Casing Point Programs. From 1996 through 1998, Brigham has entered into annual agreements with certain industry parties to participate in all of the wells drilled by the Company during the term of the agreement on a promoted drilling cost basis. For example, in order to participate in wells drilled by the Company between April 1, 1998 and March 31, 1999, Gasco Limited Partnership ("Gasco") agreed to fund 8% of the Company's drilling costs and 4% of its completion costs for each well. In return, the Company agreed to assign to Gasco an undivided 4% of the Company's interest in the leasehold allocated to the production unit for each completed well. As a result, the Company pays for 92% of costs attributable to its working interest to casing point, and 96% of its completion costs, for 96% of its original working interest for each well funded during the term of the agreement.

Brigham entered into a carry-to-casing point agreement in late 1998 with a major drilling contractor to participate in four wells drilled by the Company. Pursuant to the agreement, the drilling contractor agreed to fund 25% of the Company's drilling costs and 12.5% of its completion costs for each of these four wells. In return, the Company agreed to utilize the drilling contractor's services for the drilling of the wells and to assign to the drilling contractor an undivided 12.5% of the Company's interest in the leasehold allocated to the production unit for each completed well. As a result, the Company pays for 75% of costs attributable to its working interest to casing point, and 87.5% of its completion costs, for 87.5% of its original working interest for each well drilled under the agreement. Brigham is currently in discussions with the drilling contractor to extend this arrangement to provide for the participation in all of the wells spud by the Company over an annual term. However, there can be no assurance that such an arrangement will be reached or that the terms of any such arrangement will not differ from those in its prior agreements. The Company believes that current industry conditions have provided it with the opportunity to seek such arrangements with industry service providers to fund a portion of its capital expenditures in exchange for service commitments with such providers at competitive prices.

The Company believes that its carry-to-casing point agreements have been beneficial because they have allowed the Company to leverage its working interests in its properties by requiring it to bear a disproportionately smaller share of drilling costs, thereby enhancing its returns on drilling capital investments. Depending on future conditions, the Company may seek to enter into similar types of arrangements with industry or financial participants. To the extent that the Company does seek to enter into such future arrangements, the terms of these arrangements, including the percentages of costs borne and interests assigned, may vary from those in the Company's past and present arrangements.

Duke Project Financing. In February 1999, the Company 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 as part of its Anadarko Basin Alliance II program. In this transaction, the Company conveyed 100% of its working interest (land and seismic) in these project areas to a newly formed limited liability company (the "Duke LLC") for total consideration of $10 million. The Company is the managing member of the Duke LLC with a 1% interest, and Duke is the sole remaining member with a 99% interest. Pursuant to the terms of the Duke LLC agreement, Brigham pays 100% of the drilling and completion costs for all wells drilled by the Duke LLC within the designated project areas in exchange for a 70% working interest in the wells (and their allocable drilling and spacing units), with the remaining 30% working interest remaining in the Duke LLC, subject in each instance to proportionate reduction by any ownership rights held by third parties. Upon 100% project payout, the Company has the right to back-in for 80% of the Duke LLC's working interest in all of the then producing wells (and their allocable drilling and spacing units) and a 96% working interest in any wells (and their allocable drilling and spacing units) drilled after payout within the designated project areas governed by the Duke LLC agreement, thereby increasing the Company's effective working interest in the Duke LLC wells from 70% to 94%. The Company believes this project financing arrangement to be beneficial as it enabled Brigham to recoup substantially all of its pre-seismic land and seismic data acquisition costs incurred in these project areas and provided capital to drill the first six wells within these projects.

Natural Gas and Oil Marketing and Major Customers

Most of the Company's natural gas and oil production is sold under price sensitive or spot market contracts. The revenues generated by the Company's operations are highly dependent upon the prices of and demand for natural gas and oil. The price received by the Company for its natural gas and oil production depends on numerous factors beyond the Company's control, including seasonality, 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 natural gas and oil could have an adverse effect on the carrying value of the Company's proved reserves and the Company's revenues, profitability and cash flow. Although the Company is not currently experiencing any significant involuntary curtailment of its natural gas or oil production, market, economic and regulatory factors may in the future materially affect the Company's ability to sell its natural gas or oil production. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations", "—Risk Factors — Volatility of Natural Gas and Oil Prices" and "—Risk Factors — Marketability of Production." For the year ended December 31, 1998, sales to Highland Energy Company, Ward Petroleum Corporation, Lantern Petroleum Corporation and Louis Dreyfus Natural Gas Corporation were approximately 25%, 15%, 11% and 11%, respectively, of the Company's natural gas and oil revenues. Due to the availability of other markets and pipeline connections, the Company does not believe that the loss of any single natural gas or oil customer would have a material adverse effect on the Company's results of operations.

Competition

The oil and gas industry is highly competitive in all of its phases. The Company encounters competition from other oil and gas companies in all areas of its operations, including the acquisition of seismic and leasing options and oil and natural gas leases on properties. The Company's 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 its competitors are large, well established companies with substantially larger operating staffs and greater capital resources than the Company's. 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 the Company's financial or human resources permit. The Company's ability to acquire additional properties and to discover reserves in the future will be dependent upon its 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 Risk Factors — Competition" and "— Risk Factors — Substantial Capital Requirements."

Operating Hazards and Uninsured Risks

Drilling activities are subject to many risks, including the risk that no commercially productive reservoirs will be encountered. There can be no assurance that new wells drilled by the Company will be productive or that the Company will recover all or any portion of its 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 of drilling, completing and operating wells is often uncertain. The Company's drilling operations may be curtailed, delayed or canceled as a result of numerous factors, many of which are beyond the Company's control, including title problems, weather conditions, compliance with governmental requirements and shortages or delays in the delivery of equipment and services. The Company's future drilling activities may not be successful and, if unsuccessful, such failure may have a material adverse effect on the Company's business, financial condition or results of operations. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Risk Factors — Dependence on Exploratory Drilling Activities." In addition, use of 3-D seismic technology requires greater pre-drilling expenditures than traditional drilling strategies. Although the Company believes that its use of 3-D seismic technology will increase the probability of drilling success, some unsuccessful wells are likely, and there can be no assurance unsuccessful drilling efforts will not have a material adverse effect on the Company's business, financial condition or results of operations.

The Company's 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 properties of the Company and others. The Company maintains insurance against some but not all of the risks described above. In particular, the insurance maintained by the Company does not cover claims relating to failure of title to oil and natural gas leases, trespass during 3-D survey acquisition or surface change attributable to seismic operations, business interruption or loss of revenues due to well failure. In certain circumstances in which insurance is available the Company 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 the Company's business, financial condition and results of operations.

Employees

On March 26, 1999, the Company had 66 full-time employees. None is represented by any labor union. The Company believes its relations with its employees are good. The Company also relies on several regional consulting service companies to provide field landmen to support the Company on a project-by-project basis. One of these companies, Brigham Land Management, is owned by Vincent M. Brigham, who is the brother of Ben M. Brigham, the Company's Chief Executive Officer, President and Chairman of the Board.

Facilities

The Company's principal executive offices are located in Austin, Texas, where it leases approximately 34,330 square feet of office space at 6300 Bridge Point Parkway, Building 2, Suite 500, Austin, Texas 78730. The Company also leases a 4,100 square foot office at 450 Gears Road, Suite 240, Houston, Texas 77067.

Title to Properties

The Company believes it has satisfactory title, in all material respects, to substantially all of its producing properties in accordance with standards generally accepted in the oil and gas industry. The Company's properties are subject to royalty interests, standard liens incident to operating agreements, liens for current taxes and other inchoate burdens which the Company believes do not materially interfere with the use of or affect the value of such properties. The Company's Credit Facility (as defined) is secured by a first lien against substantially all of the Company's oil and natural gas properties and other tangible assets, and the Company's Subordinated Notes (as defined) are secured by a second lien against all collateral pledged by the Company as security under its Credit Facility. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

Governmental Regulation

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

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

Environmental Matters

The Company's 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 the Company's operations. The permits required for various of the Company's 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, the Company is in substantial compliance with current applicable environmental laws and regulations, and the Company has 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 the Company, 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 land owners 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 the Company's 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 the Company, 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 the Company. 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. With respect to certain of its operations, the Company is required to maintain such permits or meet general permit requirements. The Environmental Protection Agency ("EPA") recently adopted regulations concerning discharges of storm water runoff. This program requires covered facilities to obtain individual permits, participate in a group or seek coverage under an EPA general permit. The Company believes that it 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 the Company.

The Company has acquired leasehold interests in numerous properties that for many years have produced natural gas and oil. Although the Company believes that the previous owners of these interests have used operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties. In addition, some of the Company's properties are operated by third parties over whom the Company has no control. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Other Matters" and "— Risk Factors — Compliance with Environmental Regulations."

ITEM 2. PROPERTIES

Primary Exploration Provinces

Brigham focuses its 3-D seismic exploration efforts in natural gas and oil producing provinces where it believes 3-D technology may be effectively applied to generate relatively large potential reserve volumes per well and per field, high potential production rates and multiple producing objectives. Brigham's exploration activities are concentrated primarily in three core provinces: the Anadarko Basin of western Oklahoma and the Texas Panhandle; the onshore Gulf Coast of south Texas and, to a lesser extent, the transition zone of Louisiana; and West Texas. Brigham is concentrating substantially all of its current 3-D seismic and drilling activities on its natural gas projects in its Anadarko Basin and Gulf Coast provinces primarily due to the continuation of historically low oil prices which has made its inventory of potential drilling locations in its West Texas province less economically attractive.

Brigham has made significant investments in 3-D seismic and prospective acreage in its Anadarko Basin and Gulf Coast provinces during the past three years. Through these investments, the Company believes it has assembled an inventory of potential drilling locations that will support a multi-year drilling program, thereby providing attractive opportunities for long-term growth. Based upon the interpreted portion of its 3-D seismic data as of December 31, 1998, the Company estimates that it has identified approximately 700 potential undrilled locations within its three core exploration provinces. From inception in 1990 through 1998, Brigham has achieved net drilling costs of $0.82 per Mcfe added through its 3-D seismic exploration efforts. In addition, over 500 of Brigham's estimated potential drilling locations are in its currently active Anadarko Basin and Gulf Coast provinces where the Company has achieved inception-to-date net drilling costs of $0.68 and $0.59 per Mcfe, respectively. Furthermore, the Company estimates that approximately 800 square miles of its 1,213 total square miles of 3-D seismic data acquired in 1998 had either not been interpreted or only partially interpreted at December 31, 1998, which should provide additional potential drilling locations.

As a result of the Company's substantial investments to identify potential drilling locations and its currently limited capital resources, Brigham intends to devote substantially all of its efforts and available capital resources in 1999 to the drilling and monetization of its highest grade prospects identified or to be identified from its over 5,000 square mile inventory of 3-D seismic data. The Company's current 1999 capital budget is estimated to be $17.5 million, which represents a significant reduction from 1998 expenditures and its previously anticipated 1999 levels in an effort to match Brigham's current and expected future capital resources. The Company's budgeted 1999 capital expenditures consist of approximately $10 million to drill an estimated 20 to 25 gross wells, $3.5 million for seismic and land costs (primarily previous commitments and obligations to acquire 3-D data and acreage), and $4 million for capitalized general and administrative expenses and other fixed asset expenditures. Brigham expects that its 1999 drilling expenditures will be allocated approximately 50% to its Anadarko Basin province and 50% to its Gulf Coast province, and such expenditures will be devoted to the drilling of the highest grade prospects in the Company's inventory of identified potential drilling locations. Additionally, Brigham's 1999 drilling program will be concentrated within trends where the Company has experienced exploration success to date. Management believes that the Company has an attractive opportunity to profitably drill its highest grade 3-D delineated locations due to its historical drilling costs and the currently low cost drilling environment. Therefore, management's goal is to access additional capital to further monetize its prospect inventory. As a result, the Company's actual capital expenditures in 1999 may differ significantly from these estimates based upon capital availability during the year. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity" and "— Capital Resources".

Although the Company is interpreting 3-D seismic data within the provinces discussed below and has identified an estimated 700 potential drilling locations yet to be drilled in those provinces, there can be no assurance that any of the remaining seismic data will be interpreted or will generate additional drilling locations or that any potential drilling locations will be drilled at all or within the expected time frame. The final determination with respect to the drilling of any well, including those currently budgeted, will depend on a number of factors, including (i) the results of exploration efforts and the review and analysis of the seismic data, (ii) the availability of sufficient capital resources by the Company and other participants for drilling prospects, (iii) economic and industry conditions at the time of drilling, including prevailing and anticipated prices for oil and natural gas and the availability of drilling rigs and crews, (iv) the financial resources and results of the Company and (v) the availability of leases on reasonable terms and permitting for the potential drilling location. There can be no assurance that the budgeted wells will, if drilled, encounter reservoirs of commercial quantities of natural gas or oil.

Anadarko Basin

The Anadarko Basin is a prolific natural gas province that the Company believes offers a combination of lower risk exploration and development opportunities in shallower horizons and deeper, higher potential objectives that have been relatively under explored. This province has produced in excess of 90 Tcfe to date from numerous, historically elusive stratigraphic targets, such as the Red Fork, Upper Morrow and Springer channel sands, as well as from deeper, higher potential structural objectives, such the Lower Morrow sandstones and the Hunton and Arbuckle carbonates. In some cases, these objectives have produced in excess of 30 Bcf of natural gas from a single well at rates of up to 30 MMcf of natural gas per day. In addition, drilling economics in the Anadarko Basin are enhanced by the multi-pay nature of many of the prospects in this province, with secondary or tertiary targets serving as either incremental value or bailout potential relative to the primary target zone.

Each of the stratigraphic and structural objectives in the Anadarko Basin can provide excellent targets for 3-D seismic imaging. The Company has assembled an extensive digital data base in this province, including geologic studies, basin wide geologic tops, production data, well data, geographic data and over 8,400 miles of 2-D seismic data. Working with its team of in-house geologists and supplemented by consulting geologists, the Company's explorationists integrate this data with their extensive expertise and knowledge base to generate 3-D projects in the Anadarko Basin.

Following its initial 3-D seismic acquisition in the province in 1991 (12.5 square miles), the Company acquired 51 square miles of 3-D seismic in the Anadarko Basin in 1993. Over the last several years the Company has accelerated its activity in the Anadarko Basin, acquiring 151 square miles of 3-D seismic in 1994, 195 square miles in 1995, 457 square miles in 1996, 675 square miles in 1997 and 583 square miles in 1998. The Company retained a 75% average working interest in its 1997 and 1998 Anadarko Basin 3-D seismic projects which consisted of an aggregate of 1,258 square miles of 3-D seismic data.

As of December 31, 1998, the Company had acquired 2,124 square miles (1.4 million acres) of 3-D seismic data in the Anadarko Basin, of which an estimated 300 square miles had either not been interpreted or only partially interpreted. The Company does not currently intend to acquire additional 3-D seismic data in this province in 1999. As of December 31, 1998, Brigham had completed 71 wells in 95 attempts (75% success rate) in the Anadarko Basin and had found cumulative net proved reserves of 48 Bcfe at an average net drilling cost of $0.68 per Mcfe. In addition to its drilling activity in this province, the Company acquired 21.5 Bcfe of net proved reserves in the Anadarko Basin in late 1997 at a cost of $0.63 per Mcfe in an effort to capture additional prospects for future potential drilling. In its Anadarko Basin drilling program in 1998, the Company completed 27 wells in 40 attempts (68% success rate) with an average working interest of 50%, resulting in the addition of 9.5 net Bcfe of proved reserves (including revisions to prior years' estimates) at an average net drilling cost of $1.93 per Mcfe. Brigham's Anadarko Basin net drilling costs per Mcfe in 1998 were negatively impacted by the unsuccessful drilling of several proved undeveloped locations booked during 1997, particularly three high equity interest direct offset locations to the Company's Christopher 84 #1 Lower Morrow discovery in Hemphill County, Texas, and by several unsuccessful exploratory wells with high equity interests that were drilled late in the year. Despite the disappointing drilling costs realized in 1998, the Company has achieved average net drilling costs of $0.68 per Mcfe in its Anadarko Basin province from 1994 to 1998. As of December 31, 1998, the Company had identified an estimated 430 3-D delineated potential drilling locations in the Anadarko Basin, of which the Company intends to drill 10 to 15 gross wells in 1999 with an estimated average working interest of 40%.

As part of its strategic initiatives to improve its capital resources and liquidity in 1999, Brigham is currently marketing three producing property packages among its Anadarko Basin province reserve base. These three packages consist of proved reserves totaling approximately 41 net Bcfe as of December 31, 1998. The Company may or may not divest all or a portion these reserves, depending primarily upon the offers received during the marketing process.

Brigham intends to focus its 1999 exploration activities in its Anadarko Basin province in the following key project areas:

Arnett Project

Brigham's Arnett Project covers approximately 129,000 acres in Ellis County, Oklahoma, and targets Morrow and Hunton producing horizons at depths of 10,000 to 14,000 feet. In 1997 and 1998, the Company acquired 127 square miles of 3-D seismic in the first three of four planned phases of this project. Following seismic interpretation and initial prospect delineation on this data, Brigham began drilling in the Arnett Project in late 1998. While two of the first three exploration wells in this project were unsuccessful, the Company was completing a fourth well in mid-March 1999 in the primary objectives, the Hunton and Morrow, and has logged additional pay behind pipe in a secondary pay zone, the Tonkawa. Successful completion and production results from this well could provide offset development drilling opportunities particularly for the Morrow which is productive in the immediate area. In mid-March 1999, a fifth well was drilling in this project, also targeting the Hunton and Morrow as primary objectives. Following the sale of a portion of its interest in this project in early 1999, Brigham retains a 70% effective working interest in its Arnett Project. See "Item 1. Business — Industry Alliances — Duke Project Financing".

Falcon Project

Brigham's Falcon Project covers approximately 43,500 acres in the northeastern portion of the Texas Panhandle in Lipscomb County, Texas. This project is located in an area which produces from a number of Pennsylvanian-aged sands, with primary targets in the Upper and Lower Morrow and secondary targets in the shallower Tonkawa and Cleveland sands. The Upper and Lower Morrow zones produce from horizons in the area at depths ranging from 9,000 to 12,000 feet. The Falcon Project is located within a trend where Brigham has considerable exploration history having acquired over 280 miles of 3-D seismic and discovered over 37 Bcfe of gross reserves in the Upper and Lower Morrow reservoirs. Based on this historical success, the Company acquired an additional 68 square miles of 3-D seismic data in its Falcon Project during the second half of 1998 and has already delineated several Upper and Lower Morrow prospects in the early stages of interpretation. Brigham spud the first exploration well in its Falcon Project in March 1999 to test a potentially significant Lower Morrow sand structural feature with associated upside potential in the shallower Tonkawa sands. Based on predrill estimates, gross unrisked reserve potential for this structural prospect is over 5 Bcfe. Following the sale of a portion of its interest in this project in early 1999, Brigham retains a 70% effective working interest in its Falcon Project. See "Item 1. Business — Industry Alliances — Duke Project Financing".

Gold Project

The Gold Project is located in Dewey and Blaine Counties, Oklahoma, and targets dual natural gas producing objectives in the Morrow sandstones and Hunton carbonates at depths of 9,500 to 11,500 feet. The initial acquisition of 89 square miles of 3-D seismic data covering the project acreage was completed in 1996 and drilling activity commenced in 1998 resulting in two Hunton and one Morrow discovery. The Thomas #2 well (Brigham 34% working interest) discovered 2.4 gross Bcfe of proved reserves in the Hunton formation at a depth of 11,450 feet and was producing 2.5 MMcf of natural gas per day in mid-March 1999. The Thomas #2 is producing from a location which is believed to be associated with a potentially larger Hunton natural gas accumulation which could lead to several development locations. The Willie Porter #1 well (Brigham 34% working interest) found 2.3 gross Bcfe of proved reserves in the Hunton formation at 12,250 feet and was producing at a rate of 570 Mcf of natural gas per day in mid-March 1999. In late 1998, the Sturgeon State #1 (Brigham 34% working interest) was completed in a Morrow sand zone and was producing 70 Bbls of oil per day in mid-March 1999 before stimulation of the well. The Company and its participants have a number of additional Hunton and Morrow locations, mostly extensional and developmental in nature, planned for drilling in the Gold Project in 1999. Brigham has a 37.5% working interest in its Gold Project.

Huskie and Boilermaker Projects

Brigham's Huskie and Boilermaker Projects consist of 103 and 96 square miles, respectively, of continuous 3-D seismic data covering approximately 127,000 acres in Blaine County, Oklahoma. These projects target stratigraphic sand channels in the Springer with additional stratigraphic sand objectives in the Red Fork and Morrow in several identified prospects. Brigham initiated acquisition of data in its Huskie Project in 1996 where it retained a 37.5% working interest and, based upon the prospect density and reserve potential interpreted from this initial data set, the Company subsequently acquired data in its adjacent Boilermaker Project in 1998 where it retained a 100% working interest. The Company assembled acreage over a number of potential drilling locations in these project areas during 1998 and has at least one exploratory well planned for each project in 1999. An exploratory well in the Huskie Project will test a prospect with greater than 15 Bcfe of gross unrisked reserve potential which is an extension to a prolific Springer channel that has produced over 128 Bcfe of natural gas. Success from this initial exploratory well would likely establish several development locations.

Wildcat and Panther Projects

The Company's Wildcat and Panther Projects consist of 50 and 99 square miles, respectively, of continuous 3-D seismic data covering approximately 95,000 acres in the southern portion of the Texas Panhandle in Wheeler County, Texas and Beckham County, Oklahoma. The primary exploration targets within these projects are high potential, structural features at depths ranging from 7,500 to 21,000 feet. Brigham initiated acquisition of data in its Wildcat Project in 1997 where it retained a 37.5% working interest. Based upon the interpretation of this initial data set, the Company subsequently acquired data in its adjacent Panther Project in 1998 where it retained a 100% working interest. In its Wildcat Project, the Company has a deep 21,000 foot exploratory well planned for the second half of 1999 to drill an updip location to a Hunton well that has produced over 14.5 Bcfe since 1981 and was still producing in mid-March 1999. The Company believes successful completion of this exploratory test could prove up an additional 27 Bcfe of remaining gross unrisked reserves in the attic of this producing structure. Also in the second half of 1999, the Company plans to drill a 7,500 foot test for 17 Bcfe of gross unrisked potential reserves in a dual objective Brown Dolomite/Granite Wash structure.

Chitwood Project

Brigham's Chitwood Project consists of approximately 13 square miles of 3-D seismic data located in the prolific Carter Knox anticline in Grady County, Oklahoma. This project targets a mix of intermediate and deep prospects that range from lower risk, development locations to higher risk, exploratory objectives. Brigham initially entered this area with its 24 square mile West Bradley Project acquired in 1994. In November 1997, the Company acquired an interest in the producing Chitwood properties and undeveloped acreage which is located adjacent to the West Bradley Project area. During 1998, as part of a larger 142 square mile non-proprietary 3-D survey, Brigham and its project participant acquired 13 square miles of 3-D seismic data over the entire Chitwood Project, which led to the delineation of a number of prospects in the Springer, Big Four, and Bromide that are developmental and extensional in nature. In addition, the Company also imaged a large Arbuckle structure with in excess of 100 Bcfe of gross unrisked reserve potential which has not been optimally tested. The targeted objectives in the Chitwood Project range in depth from 12,000 to 19,000 feet. In March 1999, the Company and its project participant drilled the first well in the Chitwood Project based upon interpretation of the recently acquired 3-D seismic data. The Chitwood Boatwright Sand Unit #9 (Brigham working interest 50%) was completed in the Springer formation at a depth of 11,970 feet and was testing 300 Bbls of oil and 500 Mcf gas per day in mid-March 1999. Brigham and its project participant have delineated over 25 potential 3-D drilling locations among the four primary objectives within the Chitwood Project. Brigham has retained a 50% working interest in its Chitwood Project.

As part of its strategic initiatives to raise capital for its 1999 exploration program, the Company is marketing its 50% working interest in acreage and producing wells in the Chitwood Project. To the extent that the Company does not receive adequate offers for its interest in this project, Brigham may retain its interest and engage in further drilling of its identified locations in the Chitwood Project during 1999.

Gulf Coast

The onshore Gulf Coast region of Texas and South Louisiana is a high potential, multi-pay province that lends itself to 3-D seismic exploration due to its substantial structural and stratigraphic complexity. The Company has assembled a digital data base including geographical, production, geophysical and geological information that the Company evaluates on its CAEX workstations. Working with a team of in-house geologists supplemented by consultants, the

Company integrates this data with their extensive expertise and knowledge base to generate 3-D projects in the Gulf Coast. The Company has assembled projects in the Expanded Wilcox and Expanded Vicksburg trends in South Texas, the Miocene and Upper, Middle, and Lower Frio trends of the mid-to-southern regions of Texas, and the Lower Miocene trend in the transition zone of South Louisiana, each of which are active 3-D seismic exploration trends.

Brigham was attracted to the Gulf Coast province because of the opportunity to apply the Company's established 3-D seismic exploration approach and its staff's extensive Gulf Coast experience to a prolific, highly complex structural province with potential to discover significant natural gas reserves and production. The Company initiated its Gulf Coast effort in 1995 with the acquisition of 39 square miles of seismic data in its Esperson Dome Project in which the Company retained a small net profits interest that converts to a variable back-in working interest of 12% to 20% upon project payout. Brigham's exploration efforts in its Esperson Dome Project to date have yielded the discovery of approximately 22 Bcfe of gross proved reserves from 11 wells, mostly from objectives above 6,000 feet, with a number of prospects still remaining to be drilled. Over the last three years the Company has accelerated its activity in the Gulf Coast, acquiring 115 square miles of 3-D seismic in 1996, 404 square miles in 1997, and 590 square miles in 1998. The Company retained a 77% average working interest in its Gulf Coast 3-D seismic projects acquired from 1996 through 1998 which consisted of an aggregate of 1,109 square miles of 3-D seismic data. Brigham anticipates that its increased project assemblage and 3-D seismic acquisition activity in the Gulf Coast will result in the allocation of a higher percentage of its drilling budget to this province in 1999, and will be a significant factor in the Company's future growth.

A portion of Brigham's 3-D seismic data acquisition in the Gulf Coast has been accomplished by the Company's participation in certain non-proprietary, or speculative, seismic programs. By converting certain of the Company's proprietary seismic projects in core exploration areas to speculative data, the Company was able to leverage these proprietary projects for access to substantially larger non-proprietary speculative data for minimal or no additional cost to the Company. The Company believes this 3-D seismic acquisition strategy in the Gulf Coast, in certain circumstances, can accelerate the addition of attractive potential drilling locations in targeted trends at costs that are considerably less than those associated with proprietary 3-D seismic programs, thereby enhancing expected project rates of return.

As of December 31, 1998, the Company had acquired 1,148 square miles (734,720 acres) of 3-D seismic data in its Gulf Coast province, of which an estimated 470 square miles had either not been interpreted or only partially interpreted. The Company does not currently intend to acquire additional 3-D seismic data in this province in 1999. As of December 31, 1998, Brigham had completed 25 wells in 32 attempts (78% success rate) in the Gulf Coast and had found cumulative proved reserves of 24 net Bcfe at an average net drilling cost of $0.59 per Mcfe. In its Gulf Coast drilling program in 1998, the Company completed 17 wells in 21 attempts with an average working interest of 59% adding 21 net Bcfe of proved reserves (including revisions to prior years' estimates) at an average net drilling cost of $0.64 per Mcfe. As of December 31, 1998, the Company had identified an estimated 120 3-D delineated potential drilling locations in the Gulf Coast province, of which the Company intends to drill 10 gross wells in 1999 with an estimated average working interest of 55%.

Brigham intends to focus its 1999 exploration activities in its Gulf Coast province in the following key project areas:

Diablo Project

Brigham's Diablo Project covers 57 square miles in Brooks County, Texas, and targets shallow Frio and deep Vicksburg producing horizons. The Company has entered into a venture with a major integrated oil company that controls adjoining acreage to explore on the combined acreage for potential below 10,000 feet in the Vicksburg formation. Brigham has retained a 34% working interest in this joint exploration project. However, in prospective zones above 10,000 feet, primarily the Frio, Brigham has retained a 100% working interest in its original 4,000 acre lease block. The Company initially acquired 25 square miles of proprietary 3-D seismic in this project in 1997, and acquired an additional 33 square miles in 1998 in its Diablo Project. The Company and its participant control approximately 12,000 net acres of leasehold in this project area.

In the fourth quarter of 1998, Brigham made a potentially significant Lower Vicksburg discovery in its Diablo Project with the completion of the Brigham Palmer State #1 well (Brigham 33% working interest). The Palmer State #1 was successfully completed in three of five possible Lower Vicksburg pay zones at a depths ranging from 9,600 to 12,800 feet and had initially tested at a rate of 2.8 MMcf of natural gas and 668 Bbls of condensate per day. This discovery well appears to be located on the downdip flank of a structure which exceeds 800 acres in closure and contains potential reserves exceeding 50 Bcfe. A minimum of five potential development locations have been identified on the crest of the structure which are updip to the Palmer State #1 discovery well, the first of which is expected to spud in the late second or early third quarter of 1999. In addition, the Company has identified a large, downthrown, four-way closure in an adjacent fault block which has produced over 86 Bcfe from the Frio formation, but which has not been tested in the equivalent Vicksburg sands that produce in the Company's Palmer State #1 well. Brigham plans to spud an exploratory well to test this high potential faulted closure in mid-1999.

Southwest Danbury Project

Located in Brazoria County, Texas, Brigham's Southwest Danbury Project is an approximate 29 square mile 3-D project targeting a series of pressured Lower Frio sands at depths ranging from 12,000 to 13,000 feet. In the first half of 1998, the Brigham Nold Gas Unit #1 (Brigham working interest 46%) was drilled to a depth of approximately 12,700 feet to test a Lower Frio amplitude, or bright spot, and encountered 29 feet of net pay in the Rucks interval of the Lower Frio sands. This well has produced at an average daily rate of 2.6 MMcf of natural gas with 17 Bbls of condensate and 13 Bbls of water since August 1998. Based on the results from this initial well, the Company spud the Brigham Renn Gas Unit #1 (Brigham working interest 83.5%) in December 1998 to test another Lower Frio 3-D bright spot prospect with over 6 Bcfe gross unrisked reserve potential. This well reached total depth and was in the process of completing in late March 1999. In addition, Brigham is evaluating several additional Lower Frio prospects in its Southwest Danbury Project which could expose the Company to significant upside potential.

Hawkins Ranch Project

Brigham's Hawkins Ranch Project is a 160 square mile 3-D seismic program in the Miocene/Frio trend located in Matagorda County, Texas. In 1998, the Company acquired approximately 85 square miles of new proprietary 3-D seismic that was converted to speculative data and merged with 65 square miles of adjacent speculative 3-D data already in inventory. The Hawkins Ranch Project targets potential in the shallow, nonpressured Miocene and Frio sands as well as the deeper, pressured Frio sands. In addition to the shallow Miocene potential, the Company has identified a number of prospects targeting deeper Frio objectives in its Hawkins Ranch Project. The first exploratory Frio well is planned to spud during the second half of 1999. This well is a 14,000 foot pressured test of a 500 acre structure with associated gross unrisked reserve potential exceeding 33 Bcfe. Brigham retains a 60% working interest in this project, following the sale of a 15% interest in the project to an industry participant for $1.5 million in early 1999.

El Sauz Project

In May 1997, Brigham initiated its El Sauz Project with a seismic option covering approximately 94,000 acres in Willacy and Kennedy Counties, Texas. In 1998, the Company acquired 200 square miles of 3-D seismic data over this acreage and sold a 45% working interest in the project to two industry participants which provided the Company with significant carry on the pre-seismic land and seismic acquisition costs of the project. The El Sauz Project is an underexplored area which is bordered on three sides by Miocene and Frio fields which have in aggregate produced over 740 Bcf of natural gas and 94 MMBbls of oil. Primary targets in the El Sauz Project are expected to be in Miocene and Frio sands at depths of 4,500 to 10,000 feet, with additional potential as deep as 18,000 feet in the Lower Frio. Reserve targets range from 5 to 20 Bcf per well. Three prospects are planned for drilling in 1999, two of which target the Frio at depths of 9,300 feet and 9,800 feet and one of which is a Miocene test at 4,500 feet. Brigham retained a 55% working interest in its El Sauz Project.

West Texas

The Company's limited drilling activity in the West Texas region in 1998 was focused in the Horseshoe Atoll, the Midland Basin and the Eastern Shelf of the Permian Basin. Due to a combination of continuing low oil prices and less than anticipated drilling results in its recent exploratory activity in this province, the Company has ceased all 3-D seismic and drilling activities in its West Texas projects and intends to focus substantially all of its exploration efforts in 1999 on its predominately natural gas prospects in its Anadarko Basin and Gulf Coast provinces. To the extent that oil prices improve in the future from current levels, the Company would resume selective drilling of its remaining undrilled locations in its West Texas province if such projects are competitive with its Anadarko Basin and Gulf Coast projects based on estimated risk adjusted, pre-drill economic return analysis.

As of December 31, 1998, the Company had acquired 1,689 square miles (1.1 million acres) in the West Texas region, the vast majority of which has been interpreted. The Company does not currently intend to acquire additional 3-D seismic data in this province for the foreseeable future. As of December 31, 1998, Brigham had completed 185 wells in 298 attempts (62% success rate) with an average working interest of 23% in its West Texas province and had found cumulative proved reserves of 20 net Bcfe at an average net drilling cost of $1.39 per Mcfe. In its West Texas drilling program in 1998, the Company completed 6 wells in 11 attempts with an average working interest of 45% adding 0.5 net Bcfe of proved reserves (including revisions to prior years' estimates) at an average net drilling cost of $9.06 per Mcfe. As of December 31, 1998, the Company had an estimated 140 3-D delineated potential drilling locations in the West Texas region. The Company does not currently plan to drill any wells in its West Texas province in 1999.

Natural Gas and Oil Reserves

The Company's estimated total net proved reserves of natural gas and oil as of December 31, 1996, 1997 and 1998 and the present values attributable to these reserves as of those dates were as follows:

	As of December 31,		
	1996(1)	**1997**	**1998**
Estimated net proved reserves:			
Natural gas (MMcf)	10,257	53,230	71,166
Oil (MBbls)	1,940	3,181	4,433
Natural gas equivalent (MMcfe)	21,897	72,316	97,764
Proved developed reserves as a percentage of proved reserves	67%	65%	57%
Present Value of Future Net Revenues (in thousands)	$ 44,506	$ 69,249	$ 81,741
Standardized Measure (in thousands)	$ 44,506	$ 64,274	$ 81,649

(1) Prior to the Exchange consummated in February 1997, the Company was a partnership and not subject to income taxes. Had the Company been a taxable corporation at December 31, 1996, the Standardized Measure would have been $32.4 million, reflecting a pro forma estimate for the discounted value of future income taxes.

The reserve estimates reflected above were prepared by Cawley, Gillespie & Associates, Inc. ("Cawley Gillespie"), the Company's petroleum consultants, and are part of reports on the Company's oil and natural gas properties prepared by Cawley Gillespie. The base sales prices for the Company's reserves were $3.71 per Mcf for natural gas and $25.37 per Bbl for oil as of December 31, 1996, $2.27 per Mcf for natural gas and $15.50 per Bbl for oil as of December 31, 1997, and $2.12 per Mcf for natural gas and $9.50 per Bbl for oil as of December 31, 1998. 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 the Company's reserves at these dates.

In accordance with applicable requirements of the SEC, estimates of the Company's 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 proved reserves and future net revenues therefrom are affected by oil and natural gas prices, which have fluctuated widely in recent years. There are numerous uncertainties inherent in estimating oil and natural gas reserves and their estimated values, including many factors beyond the control of the Company. The reserve data set forth in this Form 10-K 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 the Company, 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. The Company's estimated 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 — Uncertainty of Reserve Information and Future Net Revenue Estimates."

Estimates with respect to 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

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

	Year Ended December 31,					
	1996		1997		1998	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Natural gas	5	1.2	15	6.5	30	15.6
Oil	22	5.2	21	7.9	7	2.5
Non-productive	24	7.0	26	9.8	17	8.0
Total	51	13.4	62	24.2	54	26.1
Development Wells:						
Natural gas	10	1.3	4	1.6	10	6.6
Oil	5	1.0	5	1.6	3	1.5
Non-productive	1	0.2	2	0.9	5	3.4
Total	16	2.5	11	4.1	18	11.5

The Company does not own any drilling rigs, and the majority of its drilling activities have been conducted by industry participant operators or independent contractors under standard drilling contracts. Consistent with its business strategy, the Company has continued to retain operations of an increasing number of the wells it drills. Brigham operated 57% of the gross and 76% of the net wells it participated in during 1998.

Productive Wells and Acreage

Productive Wells

The following table sets forth the Company's ownership interest as of December 31, 1998 in productive natural gas and oil wells in the areas indicated.

Province	Natural Gas Gross	Natural Gas Net	Oil Gross	Oil Net	Total Gross	Total Net
Anadarko Basin	66	21.8	18	2.1	84	23.9
Gulf Coast	15	5.7	8	3.0	23	8.7
West Texas	4	1.0	86	24.5	90	25.5
Other	—	—	5	0.8	5	0.8
Total	85	28.5	117	30.4	202	58.9

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, none 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. A gross acre is an acre in which an interest is owned. A net acre is deemed to exist when the sum of fractional ownership interests in gross acres equals one. The number of net acres is the sum of the fractional interests owned in gross acres expressed as whole numbers and fractions thereof. The following table sets forth the approximate developed and undeveloped acreage in which the Company held a leasehold, mineral or other interest at December 31, 1998:

Province	Developed Gross	Developed Net	Undeveloped Gross	Undeveloped Net	Total Gross	Total Net
Anadarko Basin	26,751	13,411	116,546	60,627	143,297	74,038
Gulf Coast	1,041	447	23,300	16,822	24,341	17,269
West Texas	6,570	1,898	18,740	7,919	25,310	9,817
Other	520	148	48,189	18,105	48,709	18,253
Total	34,882	15,904	206,775	103,473	241,657	119,377

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 Gross	Acres Expiring Net
Twelve Months Ending:		
December 31, 1999	58,205	28,464
December 31, 2000	60,347	26,998
December 31, 2001	68,759	41,222
Thereafter	19,464	6,789
Total	206,775	103,473

In addition, the Company had lease options as of December 31, 1998 to acquire an additional 173,670 gross (128,166 net) acres, substantially all of which expire within eighteen months.

Volumes, Prices and Production Costs

The following table sets forth the production volumes, average prices received and average production costs associated with the Company's sale of oil and natural gas for the periods indicated.

	Year Ended December 31,		
	1996	**1997**	**1998**
Production:			
Natural gas (MMcf)	698	1,382	4,269
Oil (MBbls)	227	291	396
Natural gas equivalent (MMcfe)	2,060	3,126	6,644
Average sales price:			
Natural gas (per Mcf)	$ 2.30	$ 2.56	$ 2.04
Oil (per Bbl)	19.98	19.40	12.85
Average production expenses and taxes (per Mcfe)	$ 0.53	$ 0.55	$ 0.46

Costs Incurred and Capitalized Costs

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

	Year Ended December 31,		
	1996	**1997**	**1998**
Cost incurred for the year:			
Exploration	$10,527	$ 29,516	$ 67,110
Property acquisition	6,195	26,956	16,245
Development	1,328	2,953	10,427
Proceeds from participants	(4,111)	(319)	(10,502)
	$13,939	$ 59,106	$ 83,280

Costs incurred represent amounts incurred by the Company for exploration, property acquisition and development activities. Periodically, the Company will receive reimbursement of certain costs from participants in its 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

The Company is not a party to any material legal proceedings.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITYHOLDERS

No matter was submitted to a vote of the Company's securityholders during the fourth quarter of 1998.

EXECUTIVE OFFICERS OF THE REGISTRANT

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

The following table sets forth certain information concerning the executive officers of the Company as of March 31, 1999:

Name	Age	Position
Ben M. Brigham	39	Chief Executive Officer and President
Jon L. Glass	43	Vice President—Exploration
Craig M. Fleming	41	Chief Financial Officer
David T. Brigham	38	Vice President—Land and Administration, Corporate Secretary
A. Lance Langford	36	Vice President—Operations
Karen E. Lynch	37	Vice President and General Counsel

Set forth below is a description of the backgrounds of the executive officers of the Company.

Ben M. "Bud" Brigham has served as Chief Executive Officer, President and Chairman of the Board of the Company since founding the Company 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, a provider of 3-D seismic services, after earning his B.S. in Geophysics from the University of Texas. Mr. Brigham is the husband of Anne L. Brigham, Director, and the brother of David T. Brigham, Vice President—Land and Administration and Corporate Secretary.

Jon L. Glass joined the Company in 1992 and has served as Vice President — Exploration since 1994 and a Director of the Company since 1995. From 1984 to 1992, Mr. Glass served in various capacities with Santa Fe Minerals, an oil and gas exploration company, in a variety of staff and managerial positions mainly focused on Santa Fe Minerals' exploration activities in the midcontinent and Gulf of Mexico (onshore and offshore). During this time Mr. Glass also assisted in the development of exploration and acquisition opportunities for Santa Fe Minerals in Canada and South America. Mr. Glass' early geological experience includes three years with Mid-America Pipeline Company and two years with Texaco USA, serving mainly as a midcontinent exploration geologist. Mr. Glass holds a B.S. and an M.S. in Geology from Oklahoma State University and an M.B.A. from the University of Tulsa.

Craig M. Fleming has served as the Chief Financial Officer of the Company since 1993. From 1990 to 1993, Mr. Fleming served as Controller of Odyssey Petroleum Co., Ltd., an independent energy company. From 1988 to 1990, Mr. Fleming served as Controller and Treasurer for Harken Exploration Company, an independent energy company. Mr. Fleming began his career with Arthur Anderson & Co. in the Oil and Gas Audit Division and is a Certified Public Accountant. Mr. Fleming holds a B.B.A. in Accounting from Texas A&M University.

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

A. Lance Langford joined the Company as Manager of Operations in 1995 and has served as Vice President — Operations since January 1997. 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.

Karen E. Lynch joined the Company in October 1997 as General Counsel and has served as Vice President — Legal and General Counsel of the Company since February 1998. Prior to joining the Company, Ms. Lynch was a shareholder in the Dallas-based law firm of Thompson & Knight, P.C., where she practiced in the energy area since joining the firm in 1987. Ms. Lynch holds a B.B.A. in Petroleum Land Management from the University of Texas and a J.D. from the University of Oklahoma.

PART II

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

The Company's Common Stock (the "Common Stock") has been publicly traded on The Nasdaq Stock Market® under the symbol "BEXP" since the Company's initial public offering effective May 8, 1997. The following table summarizes the high and low last reported sales prices on Nasdaq for each quarterly period since the Company's initial public offering:

	Common Stock	
	High	**Low**
1997:		
Second Quarter (from May 9, 1997)	$ 8.75	$ 7.00
Third Quarter	$ 14.31	$ 8.25
Fourth Quarter	$ 17.13	$ 12.00
1998:		
First Quarter	$ 14.00	$ 10.50
Second Quarter	$ 15.50	$ 8.75
Third Quarter	$ 10.25	$ 5.13
Fourth Quarter	$ 9.50	$ 4.75

The closing market price of the Company's Common Stock on March 26, 1999 was $3.50 per share. As of March 26, 1999, the Company estimates that there were more than 80 record and 1,100 beneficial owners of the Company's Common Stock.

No dividends have been declared or paid on the Company's Common Stock to date. The Company intends to retain all future earnings for the development of its business. In addition, the Credit Facility (as defined) and the Indenture (as defined) restrict the Company's ability to pay dividends on the Company's Common Stock.

ITEM 6. SELECTED FINANCIAL DATA

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

	Year Ended December 31,					
Statement of Operations Data:	**1994**	**1995**	**1996**	**1997**		**1998**
Revenues:						
Natural gas and oil sales	$ 2,565	$ 3,578	$ 6,141	$ 9,184		$ 13,799
Workstation revenue	815	635	627	637		390
Total revenues	3,380	4,213	6,768	9,821		14,189
Costs and expenses:						
Lease operating	491	761	726	1,151		2,172
Production taxes	126	165	362	549		850
General and administrative	1,785	1,897	2,199	3,570		4,672
Depletion of oil and natural gas properties	1,104	1,626	2,323	2,743		8,410
Capitalized ceiling impairment	—	—	—	—		24,847
Depreciation and amortization	561	533	487	694		785
Total costs and expenses	4,067	4,982	6,097	8,707		41,736
Operating income (loss)	(687)	(769)	671	1,114		(27,547)
Other income (expense):						
Interest income	56	128	52	145		136
Interest expense	(668)	(936)	(1,173)	(1,190)		(7,120)
Total other income (expense)	(612)	(808)	(1,121)	(1,045)		(6,984)
Net income (loss) before income taxes	(1,299)	(1,577)	(450)	69		(34,531)
Income tax expense, net	—	—	—	(1,186)	(1)	1,186
Net loss	$ (1,299)	$ (1,577)	$ (450)	$ (1,117)	(1)	$(33,345)
Net loss per share	$ (0.15)	$ (0.18)	$ (0.05)	$ (0.10)		$ (2.64)
Weighted average common shares outstanding	8,929	8,929	8,929	11,081		12,626
Statement of Cash Flows Data:						
Net cash provided by operating activities	$ 626	$ 1,383	$ 3,710	$ 9,806		$ 13,622
Net cash used in investing activities	(5,463)	(8,005)	(11,796)	(57,300)		(85,075)
Net cash provided by financing activities	4,634	7,724	7,731	47,748		72,321
Other Financial Data:						
Capital expenditures	$ 5,445	$ 7,935	$ 13,612	$ 57,170		$ 84,055

	As of December 31,				
	1994	**1995**	**1996**	**1997**	**1998**
Balance Sheet Data:					
Cash and cash equivalents	$ 700	$ 1,802	$ 1,447	$ 1,701	$ 2,569
Oil and natural gas properties, net	11,970	18,538	28,005	84,294	134,317
Total assets	15,781	22,916	33,614	92,519	150,516
Total debt	7,950	16,000	24,000	32,000	94,786
Total equity	5,271	3,694	3,244	43,313	24,681

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

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

Overview

The Company is an independent exploration and production company that applies 3-D seismic imaging and other advanced technologies to systematically explore and develop onshore oil and natural gas provinces in the United States. From inception in 1990 through December 31, 1998, Brigham acquired 5,236 square miles of 3-D seismic data, identified an estimated 1,140 potential drilling locations and drilled 442 wells delineated by 3-D seismic analysis. Through its 3-D seismic-based drilling efforts, the Company had discovered an aggregate of 92 Bcfe of net proved reserves as of December 31, 1998. The Company believes this performance demonstrates a systematic methodology for finding oil and natural gas in onshore domestic oil and natural gas provinces.

Combining its geologic and geophysical expertise with a sophisticated land effort, the Company manages the majority of its projects from conception through 3-D acquisition, processing and interpretation and leasing. In addition, the Company manages the negotiation and drafting of most of its geophysical exploration agreements, resulting in reduced contract risk and more consistent deal terms. Because it generates most of its projects, the Company can control the size of the working interest that it retains as well as the selection of the operator and the non-operating participants. Consistent with its business strategy, Brigham has increased the working interest it retained in its projects, based on capital availability and perceived risk. The Company's average working interest in its 3-D seismic projects acquired during 1996, 1997 and 1998 was 37%, 67% and 80%, respectively, while its average working interest in its wells drilled during this period was 24%, 39% and 52%, respectively. Beginning in 1995, the Company has managed operations through the drilling and production phases on an increasing portion of its 3-D seismic projects. Brigham operated 57% of its gross wells and 76% of its net wells drilled in 1998 as compared with 10% of its gross wells and 16% of its net wells drilled in 1996.

Expenditures made in oil and natural gas exploration vary from project to project depending primarily on the costs related to land, seismic acquisition, drilling costs and the working interest retained by the Company. Historically, the Company's participants have typically borne a disproportionate share of the costs of optioning available acreage and acquiring, processing and interpreting the 3-D seismic data, and the Company and its participants each typically incurred leasing, drilling and completion costs in proportion to their ownership interests. In recent years, Brigham has retained majority working interests in its new 3-D seismic projects, and has thereby reduced the financial leverage it has historically received on the costs of optioning available acreage and acquiring, processing and interpreting the 3-D seismic data on its projects.

From inception through 1996, the Company acquired 2,761 gross (781 net) square miles of 3-D seismic data. Initially, the Company focused its efforts in West Texas. In 1995, the Company began to devote substantial attention to the Anadarko Basin, and since 1996 the Company has devoted the majority of its resources to the Anadarko Basin and Gulf Coast. With this shift in regional focus, the majority of the Company's production volumes has shifted from oil to natural gas. To finance these project generation and drilling activities, the Company supplemented cash flow from operations with private placements of debt and equity, commercial bank credit facilities and placements of working interests in projects with industry participants. As the Company's cash flows from operations and other sources of capital have increased during this period, it retained larger average working interests in its projects.

In 1997 and 1998, the Company acquired 2,475 gross (1,810 net) square miles of 3-D seismic and continued to focus the majority of its 3-D exploration efforts in the Anadarko Basin and the Gulf Coast. During the past two years, the Company acquired 1,258 square miles (51%) of 3-D seismic in the Anadarko Basin, making this basin the most active 3-D seismic acquisition province for the Company. Brigham also significantly increased its Gulf Coast activity, acquiring 994 square miles (40%) of 3-D seismic in this period. During 1997 and 1998, the Company drilled 145 gross (65.9 net) wells based on its 3-D seismic data analysis. In addition to its drilling activities, the Company acquired 21.3 net Bcfe of proved reserves and an interest in undeveloped acreage (the "Chitwood Acquisition") at the northern end of the Carter Knox anticline in Grady County, Oklahoma for $13.4 million in November 1997. As a result of these activities, the Company's net natural gas and oil production increased from 2.1 Bcfe in 1996 to 6.6 Bcfe in 1998. The Company's net production volumes consisted of 79% natural gas on an equivalent basis during the fourth quarter 1998 as compared with 36% during the fourth quarter 1996. The Company supplemented cash flow from operations in 1997 and 1998 with borrowings under commercial bank credit facilities, $24 million raised in its initial public offering of common stock in May 1997, $47.5 million raised through the placement of debt and equity securities in August 1998 and the placement of working interests in projects to industry participants to finance its project generation, property acquisition and drilling activities.

The Company uses the full-cost method of accounting for its natural gas and oil properties. Under this method, all acquisition, exploration and development costs, including certain internal costs that are directly attributable to the Company's acquisition, exploration and development activities, are capitalized in the amortizable base of the "full-cost pool" as incurred. Upon the interpretation by the Company of the 3-D seismic associated with unproved properties, the geological and geophysical costs of acreage that is not specifically identified as prospective are transferred to the amortizable base of the full-cost pool. Geological and geophysical costs associated with prospective acreage, as well as leasehold costs, are transferred to the amortizable base of the full-cost pool when the prospects are drilled. The Company records depletion of its full-cost pool using the unit of production method.

To the extent that the 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 natural gas and oil prices) of estimated future net after-tax cash flows from proved natural gas and oil reserves plus the capitalized cost of unproved properties, such costs are charged to operations as a writedown of the carrying value of natural gas and oil properties, or a "capitalized ceiling impairment" charge. The risk that the Company will be required to write down the carrying value of its oil and gas properties increases when oil and gas prices are depressed, even if such prices are temporary. In addition, capitalized ceiling impairment charges may occur if the Company experiences poor drilling results or has substantial downward revisions in its estimated proved reserves. A capitalized ceiling impairment is a charge to earnings that does not impact cash flows, but does impact operating income and stockholders' equity. Once incurred, a capitalized ceiling impairment charge to natural gas and oil properties cannot be reversed at a later date. Primarily as a result of the significant declines in both oil and natural gas prices at December 31, 1998 and disappointing drilling results on several of the Company's high working interest wells in 1998, the Company recorded a capitalized ceiling impairment charge at December 31, 1998 of $24.8 million (see Note 2 of Notes to the December 31, 1998 Consolidated Financial Statements). No assurance can be given that the Company will not experience a capitalized ceiling impairment charge in future periods. See "— Risk Factors — Dependence on Exploratory Drilling Activities"; "— Risk Factors — Volatility of Natural Gas and Oil Prices"; and " — Risk Factors — Uncertainty of Reserve Information and Future Net Revenue Estimates."

In connection with the Exchange in 1997, the Company issued options to purchase 644,097 shares of Common Stock to certain of its officers and employees. The Company recorded an unearned stock compensation balance of $2.5 million in the first quarter 1997, of which approximately one-half will be added to the amortizable base of the full-cost pool over the vesting period of the options and the balance will be recorded as a noncash compensation expense over the vesting period of the options. As a result, the Company expects to incur unearned stock compensation amortization expenses of approximately $189,000 in 1999, $115,800 in 2000 and an aggregate of $111,000 in the three years thereafter.

The Company's predecessor was classified as a partnership for federal income tax purposes. Therefore, no income taxes were paid or provided for by the Company prior to the Exchange. The Company is a taxable entity. In connection with the Exchange on February 27, 1997, the Company incurred a $5 million charge to record a deferred income tax liability to recognize the differences between the financial statement basis and tax basis of the Company's predecessor partnership's natural gas and oil properties at the Exchange date, given the provisions of enacted tax laws. During the fourth quarter 1997, the Company elected to record a step-up in the basis of its assets for tax purposes as a result of the Exchange. Due to this election, the Company recorded a $3.8 million non-cash deferred income tax benefit during the fourth quarter 1997, which resulted in a net $1.2 million ($0.10 per dividend share) non-cash deferred income tax charge for the year ended December 31, 1997.

Results of Operations

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

	Year Ended December 31,		
	1996	1997	1998
Production:			
Natural gas (MMcf)	698	1,382	4,269
Oil (MBbls)	227	291	396
Natural gas equivalent (MMcfe)	2,060	3,126	6,644
% Natural gas	34%	44%	64%
Average sales prices per unit (1):			
Natural gas (per Mcf)	$ 2.30	$ 2.56	$ 2.04
Oil (per Bbl)	19.98	19.40	12.85
Natural gas equivalent (per Mcfe)	2.98	2.94	2.08
Costs and expenses per Mcfe:			
Lease operating	$ 0.35	$ 0.37	$ 0.33
Production taxes	0.18	0.18	0.13
General and administrative	1.07	1.14	0.70
Depletion of natural gas and oil properties	1.13	0.88	1.27

(1) Reflects the effects of the Company's hedging activities. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Other Matters — Hedging Activities."

Year Ended December 31, 1998 Compared to Year Ended December 31, 1997

Natural gas and oil sales. Natural gas and oil sales increased 50% from $9.2 million in 1997 to $13.8 million in 1998. Production volume increases accounted for $9.4 million (204%) of this increase and were offset by $4.8 million (104%) from a decrease in the average sales price received for natural gas and oil sales. Production volumes for natural gas increased 209% from 1,382 MMcf in 1997 to 4,269 MMcf in 1998. The average price received for natural gas decreased 20% from $2.56 per Mcf in 1997 to $2.04 per Mcf in 1998. Production volumes for oil increased 36% from 291 MBbls in 1997 to 396 MBbls in 1998. The average price received for oil decreased 34% from $19.40 per Bbl in 1997 to $12.85 per Bbl in 1998. Natural gas and oil sales in 1998 were increased by production from wells completed and flowing to sales since December 31, 1997, offset partially by the natural decline of existing production, and from certain wells acquired in the Chitwood Acquisition which were included in the Company's results of operations effective September 1, 1997. As a result of hedging activities, natural gas revenues increased by $555,240 ($0.13 per Mcf) in 1998, compared to a decrease in oil revenues of $6,191 ($0.02 per Bbl) in 1997. See "— Other Matters — Hedging Activities."

Workstation revenue. Workstation revenue decreased 39% from $637,000 in 1997 to $390,000 in 1998. Workstation revenue is recognized by the Company as industry participants in the Company's seismic programs are charged an hourly rate for the work performed by the Company on its 3-D seismic interpretation workstations. This decrease is primarily attributable to the Company's increased working interests in its recently acquired 3-D seismic data, which reduces the amount of workstation interpretation costs that the Company can bill to its participants. The Company expects workstation revenue to continue to decline in 1999 due to the Company's increased working interests in the square miles of 3-D seismic it acquired in 1997 and 1998.

Lease operating expenses. Lease operating expenses increased 89% from $1.2 million ($0.37 per Mcfe) in 1997 to $2.2 million ($0.33 per Mcfe) in 1998. This increase was primarily due to an increase in the number of producing wells during 1998 from those in 1997. The decrease in the per unit amount was primarily due to an increase in natural gas production as a percentage of total equivalent production (44% in 1997 and 64% in 1998) since a typical natural gas well produces with lower average lease operating costs per unit of production than a typical oil well.

Production taxes. Production taxes increased 55% from $549,000 ($0.18 per Mcfe) in 1997 to $850,000 ($0.13 per Mcfe) in 1998 as a direct result of increased production volumes. The effective average production tax rate increased from 6% of natural gas and oil sales revenues in 1997 to 6.2% in 1998 due to the increase in natural gas production as a percentage of total equivalent production as natural gas is typically burdened with higher production tax rates than oil. The decrease in the per unit amount was primarily attributable to the decline in natural gas and oil sales prices in 1998 as compared with 1997.

General and administrative expenses. General and administrative expenses increased 31% from $3.6 million ($1.14 per Mcfe) in 1997 to $4.7 million ($0.70 per Mcfe) in 1998. This increase was primarily attributable to the hiring of additional personnel and related expenses necessary to manage the Company's growing operations. The decrease in the per unit rate was a result of a greater increase in natural gas and oil production volumes than general and administrative expenses from 1997 to 1998 due to the aforementioned factors. The Company has initiated an overhead reduction plan during 1999, consisting primarily of a Company-wide salary reduction beginning in the second quarter of 1999 and the elimination or reduction of various other discretionary administrative expenditures. The Company plans to continue to evaluate its overhead cost structure during the course of 1999 and may take further steps to reduce its administrative expenses depending upon the outcome of its various strategic initiatives underway to improve its capital resources and liquidity.

Depletion of natural gas and oil properties. Depletion of natural gas and oil properties increased 207% from $2.7 million ($0.88 per Mcfe) in 1997 to $8.4 million ($1.27 per Mcfe) in 1998. Of this increase, $4.5 million was attributable to the increase in production volumes during the period and $1.2 million was due to the increase in the depletion rate per unit of production. The increase in depletion rate per unit of production was primarily the result of the addition of natural gas and oil reserves at higher average capital costs due to a reduction in drilling performance and downward revisions to previous reserve estimates.

Interest expense. Interest expense increased from $1.2 million in 1997 to $7.1 million in 1998 due to the Company's higher average outstanding debt balance in 1998 combined with a higher average effective interest rate. The Company's weighted average outstanding debt balance increased 450% from $12 million in 1997 to $66 million in 1998. This increase in debt was incurred primarily to fund the Company's increased capital expenditures and working capital needs, net of operating cash flow, during 1998. The effective annual interest rate on the Company's outstanding indebtedness increased from 9.4% in 1997 to 10.6% in 1998, primarily due to the Company's issuance of $40 million of Senior Subordinated Secured Notes due 2003 (the "Subordinated Notes") in August 1998, which bore interest at an annual rate of 12% from the date of issuance. In addition, interest expense in 1998 included (i) approximately $1 million of non-cash charges related to the amortization of deferred loan fees and the amortization of discount on the Subordinated Notes, and (ii) $507,000 of interest expenses related to the Subordinated Notes that was paid through the issuance of additional Subordinated Notes in lieu of cash in February 1999. Pursuant to the recently amended terms of the Credit Facility and the Subordinated Notes, the Company expects to pay its interest obligations related to the Subordinated Notes in 1999 through the issuance of additional Subordinated Notes in lieu of cash in an effort to preserve cash flow to fund capital expenditures and working capital. Borrowings under the Company's commercial bank credit facility had an effective annual interest rate of 7.2% at December 31, 1998. See "— Liquidity" and "— Capital Resources."

Year Ended December 31, 1997 Compared to Year Ended December 31, 1996

Natural gas and oil sales. Natural gas and oil sales increased 50% from $6.1 million in 1996 to $9.2 million in 1997. Production volume increases accounted for $3.2 million (104%) of this increase and were offset by $134,000 (4%) from a decrease in the average sales price received for natural gas and oil sales. Production volumes for natural gas increased 98% from 698,036 Mcf in 1996 to 1,381,996 Mcf in 1997. The average price received for natural gas increased 11% from $2.30 per Mcf in 1996 to $2.56 per Mcf in 1997. Production volumes for oil increased 28% from 226,925 Bbls in 1996 to 290,624 Bbls in 1997. The average price received for oil decreased 3% from $19.98 per Bbl in 1996 to $19.40 per Bbl in 1997. Natural gas and oil sales were increased by production from 46 wells completed in 1997, which was partially offset by the natural decline of existing production. Hedging activities in 1997 reduced the amount by which oil revenues increased by $6,191, compared to a decrease in oil revenues of $301,280 as a result of hedging activities in 1996.

Workstation revenue. Workstation revenue increased 2% from $627,000 in 1996 to $637,000 in 1997. Workstation revenue is recognized by the Company as industry participants in the Company's seismic programs are charged an hourly rate for the work performed by the Company on its 3-D seismic interpretation workstations.

Lease operating expenses. Lease operating expenses increased 59% from $726,000 ($0.35 per Mcfe) in 1996 to $1.2 million ($0.37 per Mcfe) in 1997. The increase was primarily due to an increase in producing wells during the year.

Production taxes. Production taxes increased 52% from $362,000 ($0.18 per Mcfe) in 1996 to $549,000 ($0.18 per Mcfe) in 1997 as a direct result of increased production volumes. The effective average production tax rate remained unchanged at 6% of natural gas and oil sales revenues for each period.

General and administrative expenses. General and administrative expenses increased 62% from $2.2 million ($1.07 per Mcfe) in 1996 to $3.6 million ($1.14 per Mcfe) in 1997. Approximately $300,000 of the increase in 1997 resulted from nonrecurring expenses related to the Company's relocation of its corporate headquarters from Dallas, Texas to Austin, Texas, and the balance was primarily attributable to the hiring of additional personnel and related expenses necessary to manage the Company's growing operations. The increase in the per unit rate was a result of a greater increase in aggregate general and administrative expenses than natural gas and oil production volumes from 1996 to 1997 due to the aforementioned factors.

Depletion of natural gas and oil properties. Depletion of natural gas and oil properties increased 18% from $2.3 million ($1.13 per Mcfe) in 1996 to $2.7 million ($0.88 per Mcfe) in 1997 as a result of higher production volumes. The per unit amount decreased due to the addition of proved reserves during 1997.

Interest expense. Interest expense was essentially unchanged from 1996 to 1997 as the Company's lower average outstanding debt balance in 1997 was offset by a higher effective average interest rate. The weighted average outstanding debt balance decreased 39% from $19.7 million in 1996 to $12 million in 1997. The effective interest rate increased 83% from 5.7% in 1996 to 10.5% in 1997. The decrease in the weighted average outstanding debt balance and increase in the effective average interest rate resulted primarily from the conversion to equity of privately placed 5% notes in February 1997, the retirement of $13.3 million of borrowings under its previous credit facility in connection with the Company's May 1997 initial public offering, and $32 million of borrowings incurred under its previous credit facility subsequent to the Company's initial public offering to fund the Company's increased exploration activity and its $13.5 million acquisition of properties from Mobil adjacent to its West Bradley 3-D Project area. The Company's previous credit facility had an effective interest rate of 8.8% at December 31, 1997.

Liquidity

Despite the Company's success in building its inventory of 3-D seismic data and potential drilling locations, a number of key factors have recently contributed to significantly limit the Company's capital resources available to fund its continued long-term growth-oriented exploration strategy. Management believes these principal factors include: (i) lower commodity sales prices, which reduced revenues and cash flow from the Company's production volumes, (ii) reduced access to public, private and industry sources of capital on cost-effective terms due to the continuing low commodity price environment and outlook, (iii) less than anticipated success in placing working interests with industry or financial participants in certain of its high equity interest projects, resulting in lower levels of project cost recoupment than budgeted, (iv) high levels of expenditures for 3-D seismic and land activities that do not generate proved reserves and cash flow until the drilling stage of the project cycle, (v) the utilization of high levels of debt to fund its accelerating exploration expenditures, and (vi) disappointing drilling results during 1998 on a number of high equity interest exploratory and development wells, several of which were completed and subsequently plugged and abandoned or otherwise performed below expectations.

As a result of these limiting factors and an expectation for continuing difficult industry and capital markets conditions, Brigham has substantially reduced its planned capital budget for 1999 and has undertaken a number of strategic initiatives in an effort to improve and preserve its capital liquidity in the current environment. While the Company remains focused on its long-term growth objectives and the continuation of its established business model for 3-D seismic-based exploration, Brigham has adapted its business strategy in the near-term in an effort to maximize value for its shareholders on a long-term basis through the implementation of the following principal strategic initiatives: (i) focusing all of the Company's planned exploration efforts in 1999 toward the drilling of its highest-grade 3-D prospects identified in its Anadarko Basin and Gulf Coast projects, concentrated primarily in trends where Brigham has achieved exploration success, (ii) eliminating substantially all planned seismic and land expenditures for new projects until its capital resources can support such additional activity, (iii) seeking to divest certain producing natural gas and oil properties in an effort to raise capital to reduce debt borrowings and to redirect capital to drilling projects that have the potential to generate higher investment returns, (iv) restructuring its outstanding senior and subordinated debt agreements to provide the Company with flexibility needed to preserve cash flow to fund its expected near-term exploration activities, (v) implementing an overhead reduction plan to reduce general and administrative expenses, and (vi) evaluating opportunities to raise additional equity capital either through the sales of interests in certain of its seismic projects or the issuance of equity securities. The Company believes that the successful execution of these strategic initiatives will provide Brigham with sufficient capital resources to execute its planned 1999 exploration program and position the Company to realize the significant value it believes it has captured in its inventory of 3-D seismic projects and delineated drilling locations. While the Company has initiated each of these strategic directives in late 1998 and early 1999, and has effected certain of them to date, the successful completion of any or all of these efforts to improve the Company's capital availability within the expected timeframe is uncertain and will likely have a material impact on the Company's near-term capital expenditure levels and growth profile.

On March 30, 1999, the Company entered into an agreement with Veritas DGC Land, Inc. ("Veritas") to exchange 1,002,865 shares of newly issued Brigham common stock valued at $3.50 per share for approximately $3.5 million of payment obligations due to Veritas in 1999 for certain seismic acquisition and processing services previously performed. In addition, this agreement provides for the payment by Brigham of up to $1 million in future seismic processing services to be performed by Veritas in newly issued shares of Brigham common stock valued at $3.50 per share, in the event that the Company does not elect to pay for such services in cash. The settlement of these future seismic processing services will be determined on a quarterly basis through December 31, 1999. Brigham considers this arrangement to be beneficial as it will enable the Company to reduce its working capital commitments and preserve additional cash flow and capital availability to fund its 1999 drilling program.

Capital Resources

The Company's primary sources of capital have been revolving credit facility and other debt borrowings, public and private equity financings, the sale of interests in projects and funds generated by operations. The Company's primary capital requirements are 3-D seismic acquisition, processing and interpretation costs, land acquisition costs and drilling expenditures. During May 1997, the Company completed an initial public offering of common stock of the Company that generated proceeds of approximately $24 million, net of offering costs, that were used to repay all outstanding debt ($13.3 million) under the Company's then existing revolving credit facility and to fund capital expenditures. In January 1998, the Company entered into a new revolving credit facility that provided for borrowing availability of $75 million that was used to repay its then outstanding borrowings under its previous credit facility and to fund capital expenditures. In August 1998, the Company issued $50 million of debt and equity securities, including the $40 million of Subordinated Notes, that generated proceeds of approximately $47.5 million, net of offering costs, that were used to repay a portion of then outstanding borrowings under the Credit Facility, thereby increasing the Company's borrowing availability under its Credit Facility to fund capital expenditures.

Revolving Credit Facility

In January 1998, the Company entered into a new revolving credit agreement (the "Credit Facility"), which provided for borrowing availability of $75 million. The Company used a portion of the funds available under the Credit Facility to repay the $32 million in borrowings outstanding at December 31, 1997 under its previous commercial bank credit facility. Principal outstanding under the Credit Facility is due at maturity on January 26, 2001 with interest due monthly for base rate tranches or periodically as LIBOR tranches mature. The annual interest rate for borrowings under the Credit Facility has been either the lender's base rate or LIBOR plus 2.25%, at the Company's option. The Credit Facility's borrowing availability was subsequently reduced from $75 million to $65 million upon the Company's issuance of the Subordinated Notes in August 1998.

In March 1999, the Company and its lenders entered into an amendment to the Credit Facility. Pursuant to this amendment, the borrowing availability under the Credit Facility will remain at $65 million until June 1, 1999, when the borrowing availability will be redetermined by the lenders based on the Company's then proved reserve value and cash flows. In addition, certain financial covenants of the Credit Facility have been amended, additional covenants have been included that place significant restrictions on the Company's ability to incur certain capital expenditures, the annual interest rate for borrowings under the Credit Facility has been amended to the lender's base rate or LIBOR plus 3.00%, and the Company will pay the lenders a $500,000 transaction fee over a ten month period. The Company's obligations under the Credit Facility are secured by substantially all of the natural gas and oil properties and other tangible assets of the Company. At March 26, 1999, the Company had $59 million in borrowings outstanding under the Credit Facility, which bear interest at an annual rate of 7.4%. See Note 5 of Notes to the December 31, 1998 Consolidated Financial Statements.

The Credit Facility has certain financial covenants including current and interest coverage ratios, as defined. The Company and its lenders effected the recent amendment to the Credit Facility to enable the Company to comply with certain financial covenants of the Credit Facility, including the minimum current ratio, minimum interest coverage ratio and the limitation on capital expenditures related to seismic and land activities. The Company believes this most recent amendment is indicative of its lenders' cooperation in the current oil and natural gas pricing environment. If this pricing environment continues or deteriorates further beyond the date of redetermination of borrowing availability, the Company believes its lenders will expect the Company to substantially reduce its level of borrowing under the Credit Facility. With this in mind, the Company has initiated the business strategy noted above. Should the Company be unable to comply with certain of the financial covenants, its lenders may be unwilling to waive compliance or amend the covenants in the future. In such instance, the Company's liquidity may be adversely affected, which could in turn have an adverse impact on the Company's future financial position and results of operations.

Subordinated Notes

In August 1998, the Company issued $50 million of debt and equity securities to affiliates of Enron Corp. ("Enron"). Securities issued by the Company in connection with this financing transaction included: (i) $40 million of Subordinated Notes, (ii) warrants to purchase 1,000,000 shares of the Company's common stock at a price of $10.45 per share (the "Warrants"), and (iii) 1,052,632 shares of the Company's common stock at a price of $9.50 per share. The approximate $47.5 million in net proceeds received by the Company from this financing transaction were used to repay a portion of outstanding borrowings under its Credit Facility, which increased the Company's borrowing availability under its Credit Facility to fund capital expenditures.

Principal outstanding under the Subordinated Notes is due at maturity on August 20, 2003. Interest on the Subordinated Notes is payable quarterly at rates that vary depending upon whether accrued interest is paid in cash or "in kind" through the issuance of additional Subordinated Notes ("PIK Interest"). Interest shall be paid in cash at interest rates of 12%, 13% and 14% per annum during years one through three, year four and year five, respectively, of the term of the Subordinated Notes; provided, however, that if the payment of interest accrued on the Subordinated Notes in cash would cause a borrowing base deficiency under the Credit Facility or would cause the Company to be in violation of any covenant or other restriction set forth in any senior loan document or any agreement entered into by the Company or subsidiary of the Company in connection with the Subordinated Notes, the Company may pay PIK Interest at interest rates of 13%, 14% and 15% per annum during years one through three, year four and year five, respectively, of the term of the Notes.

The Subordinated Notes rank subordinate in right of payment to Senior Indebtedness (as defined) and senior to all other financings (other than any allowed capital leases and purchase money financings) of the Company. The Subordinated Notes are secured by a second lien against substantially all of the natural gas and oil properties and other tangible assets of the Company. The Subordinated Notes may be prepaid at any time, in whole or in part, without premium or penalty, provided that all partial prepayments must be pro rata to the various holders of the Subordinated Notes. The Subordinated Notes were issued pursuant to an indenture (the "Indenture") that contains certain covenants that, among other things, limit the ability of the Company and its subsidiaries to incur additional indebtedness, pay dividends, make distributions, enter into certain sale and leaseback transactions, enter into certain transactions with affiliates, dispose of certain assets, incur liens, and engage in mergers and consolidations.

In March 1999, the Company and Chase Bank of Texas, National Association, as trustee (the "Trustee") for the holders of the Subordinated Notes, entered into an amendment to the Indenture. This amendment provides the Company with the option to pay interest due on the Subordinated Notes in kind, for any reason, through the second quarter of 2000. In addition, certain financial and other covenants were amended. The amendment also provides for a reduction in the exercise price per share of the Warrants from $10.45 per share to $3.50 per share.

The Indenture governing the Subordinated Notes has certain financial covenants including current and interest coverage ratios, as defined. The Company and the holders of the Subordinated Notes effected the recent amendment to the Indenture to enable the Company to comply with certain financial covenants of the Indenture that parallel those of the Credit Facility, including the minimum current ratio and the minimum interest coverage ratio. Should the Company be unable to comply with certain of the financial covenants, the holders of the Subordinated Notes may be unwilling to waive compliance or amend the covenants in the future. In such instance, the Company's liquidity may be adversely affected, which could in turn have an adverse impact on the Company's future financial position and results of operations.

Cash Flow Analysis

Cash Flows from Operating Activities. Cash flows provided by operating activities were $13.6 million in 1998, $9.8 million in 1997, and $3.7 million in 1996. The increase in cash flows for 1998 compared to 1997 was due primarily to an increase in natural gas and oil revenues, net of lease operating expenses, production taxes and general and administrative expenses, and net changes in working capital items. The increase in cash flows for 1997 compared to 1996 was due primarily to an increase in natural gas and oil revenues, net of lease operating expenses, production taxes and general and administrative expenses.

Cash Flows from Investing Activities. Cash flows used in investing activities increased to $85.1 million in 1998 compared to $57.3 million in 1997 and $11.8 million in 1996. These increases are directly related to an increase in capital expenditures related to the Company's exploration and development activities. Capital expenditures were $84.1 million in 1998, $57.2 million in 1997 and $13.6 million in 1996.

The Company acquired 1,213 gross (968 net) square miles of 3-D seismic in 1998, 1,262 gross (842 net) square miles in 1997, and 655 gross (241 net) square miles in 1996. The Company's drilling efforts resulted in the completion of 50 wells (26.3 net) in 1998, 45 wells (17.6 net) in 1997 and 42 wells (8.7 net) in 1996, which resulted in aggregate net increases in proved reserve volumes (net of revisions to previous estimates) of 31.2 Bcfe in 1998, 32.4 Bcfe in 1997, and 11.3 Bcfe in 1996. In addition, the Company sold certain producing properties in 1996 for $2.1 million and acquired certain producing properties and related interests for $13.5 million in 1997 and $1.0 million in 1998.

Cash Flows from Financing Activities. Cash flows provided by financing activities for 1998 were $72.3 million, primarily as a result of borrowings under the Credit Facility, the issuance of the Subordinated Notes and the sale of $10 million of common stock. Cash flows from financing activities for 1997 were $47.7 million, primarily as a result of borrowings under the Company's previous credit facility and proceeds from the common stock sold in the Company's initial public offering. Cash flows from financing activities for 1996 were $7.7 million, primarily as a result of borrowings under the Company's previous credit facility.

Capital Expenditures

As a result of the Company's limited available capital resources, Brigham has significantly reduced its planned capital expenditure budget for 1999 from the Company's previously anticipated levels in an effort to match the its current and expected future capital resources. The Company's current 1999 capital budget is estimated to be $17.5 million, or approximately 21% of 1998 expenditures. The Company's budgeted 1999 capital expenditures consist of approximately $10 million to drill an estimated 20 to 25 gross wells, $3.5 million for seismic and land costs, consisting primarily of previous year commitments and obligations to acquire 3-D data and acreage, and $4 million for capitalized general and administrative expenses and other fixed asset expenditures. Brigham expects that its 1999 drilling expenditures will be allocated approximately 50% to its Anadarko Basin province and 50% to its Gulf Coast province, and such expenditures will be devoted to the drilling of the highest grade prospects in the Company's inventory of identified potential drilling locations. The Company intends to fund these budgeted capital expenditures through a combination of cash flow from operations, available borrowings under its Credit Facility and the sales of certain assets (including the potential divestitures of certain producing property packages from among its Anadarko Basin properties and interests in certain 3-D seismic projects). In addition to these sources of capital, the Company is also evaluating opportunities to raise additional capital to enable it to increase its planned capital expenditures for drilling in 1999. However, since the Company's capital availability during 1999 will depend to a large extent on the Company's success raising additional financing through its planned and potential strategic initiatives, the Company's actual 1999 capital expenditures may differ from its current estimates. In the event additional financing is not available in the amounts or timing needed, the Company may be required to curtail its planned exploration activities in 1999 and take further measures to reduce the size and scope of its business. See "Item 2. Properties — Primary Exploration Provinces."

Other Matters

Hedging Activities

The Company believes that hedging, although not free of risk, allows the Company to reduce its exposure to natural gas and oil sales price fluctuations and thereby to achieve more predictable cash flows. However, hedging arrangements, when utilized, limit the benefit to the Company of increases in the prices of the hedged commodity. Moreover, the Company's hedging arrangements apply only to a portion of its production and provide only partial price protection against declines in commodity prices. The Company expects that the amount of its hedges will vary from time to time. See "— Risk Factors — Risk of Hedging Activities" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

In 1995 the Company, in an attempt to reduce its sensitivity to volatile commodity prices, began using crude oil swap arrangements resulting in a fixed price over a period of six months. Total oil purchased and sold subject to swap arrangements entered into by the Company was 118,150 Bbls in 1996 and 54,900 Bbls in 1995. The Company accounts for all these transactions as hedging activities and, accordingly, adjusts the price received for natural gas and oil production during the period the hedged transactions occur. Adjustments to the price received for oil under these swap arrangements resulted in an increase in oil revenues of $40,849 in 1995 and decreases in oil revenues of $301,280 in 1996 and $6,191 in 1997. As of December 31, 1997, the Company had no hedging contracts outstanding.

In 1998, the Company began using natural gas swap arrangements in an attempt to reduce its sensitivity to volatile commodity prices as its production base became increasingly weighted toward natural gas. Pursuant to these arrangements the Company exchanges a floating market price for a fixed contract price. Payments are made by the Company when the floating price exceeds the fixed price for a contract month and payments are received by the Company when the fixed price exceeds the floating price. Settlements of these swaps are based on the difference between the ANR Pipeline Co.-Oklahoma index price (as published in *Inside FERC's Gas Market Report*) for a contract month and the fixed contract price for the same month.

The following table summarizes the Company's natural gas swap arrangements entered into from February 1998 through March 1999:

	Daily Volumes Hedged (MMBtu)	Monthly Term	Total Volumes Hedged (MMBtu) 1998	1999	2000	2001	Average Fixed Contract Price ($/MMBtu) (1)
Contract #1	10,000	April 1998 - October 1999	2,750,000	3,040,000			$2.163
Contract #2	5,000	April 1999 - October 1999		1,070,000			$2.015
Contract #3	15,000	November 1999 - April 2001		915,000	5,490,000	1,800,000	$2.065

(1) Based on the ANR Pipeline Co.-Oklahoma index price as published in *Inside FERC's Gas Market Report*.

For the year ended December 31, 1998, the Company realized an increase in revenues attributable to natural gas hedges of $555,240.

Effects of Inflation and Changes in Prices

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

Environmental and Other Regulatory Matters

The Company's business is subject to certain federal, state and local laws and regulations relating to the exploration for and the development, production and marketing of natural gas and oil, 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 the Company believes it is in substantial compliance with all applicable laws and regulations, the requirements imposed by laws and regulations are frequently changed and subject to interpretation, and the Company is unable to predict the ultimate cost of compliance with these requirements or their effect on its operations. Any suspensions, terminations or inability to meet applicable bonding requirements could materially adversely affect the Company's financial condition and operations. Although significant expenditures may be required to comply with governmental laws and regulations applicable to the Company, compliance has not had a material adverse effect on the earnings or competitive position of the Company. Future regulations may add to the cost of, or significantly limit, drilling activity. See "— Risk Factors — Compliance with Environmental Regulations," "Item 1. Business — Governmental Regulation" and "Item 1. Business — Environmental Matters."

Year 2000 Issues

Many computer software systems, as well as certain hardware and equipment using date-sensitive data, were structured to use a two-digit date field meaning that they may not be able to properly recognize dates in the year 2000. The Company has developed a plan to address this issue and is taking steps to review its information technology systems, such as computer hardware and software, as well as non information technology systems, including computer controlled equipment and electronic devices used to operate equipment involved in processing and interpreting 3-D seismic data.

The Company has completed the initial phases of its plan by identifying all computerized systems and substantially completing an inventory of its equipment and component parts. Both information technology and non information technology systems may contain embedded technology, which complicates the Company's Year 2000 identification, assessment, remediation and testing efforts. The Company continues to inventory its equipment and facilities to determine if they contain embedded date-sensitive technology. The Company is currently reviewing all of its systems to determine which are not Year 2000 compliant and will need to be replaced or modified. This current phase includes comparisons of inventory to manufacturer's information and/or performance testing. If problems are identified, the Company will undertake remediation, replacement or alternative procedures for non-compliant equipment or facilities on a business priority basis. The Company's identification and assessment efforts to date have not identified any computer equipment or software it currently uses which will require replacement or modification, except that one of the word processing software programs the Company uses may be non-compliant and may need to be discontinued or upgraded. In addition, in the ordinary course of replacing computer equipment and software, the Company attempts to obtain replacements that are Year 2000 compliant. The Company currently anticipates that its identification, assessment, remediation and testing efforts will continue and, depending upon the results of the assessment efforts, be completed during the first three quarters of 1999.

As of December 31, 1998, all costs incurred by the Company in connection with its Year 2000 compliance efforts were included within the Company's normal general and administrative expenses (for example, regular maintenance of software programs). The Company is currently expensing as incurred all costs related to the assessment and remediation of the Year 2000 issue, and these costs are being funded through operating cash flow. However, in certain instances the Company may determine that replacing existing equipment may be appropriate and may capitalize such replacements. The Company is unable currently to estimate the amount of its total out-of-pocket costs to become Year 2000 compliant, but the Company currently expects that such costs will not have a material adverse effect on the Company's financial condition, operations or liquidity.

The foregoing timetable and assessment of costs to become Year 2000 compliant reflect management's current best estimates. These estimates are based on many assumptions, including assumptions about the cost, availability and ability of resources to locate, remediate and modify affected systems, equipment and facilities. Based upon its activities to date, the Company does not currently believe that these factors will cause results to differ significantly from those estimated. However, the Company cannot reasonably estimate the potential impact on its financial condition and operations if key third parties including, among others, suppliers, contractors, joint venture partners, financial institutions, customers and governments do not become Year 2000 compliant on a timely basis. The Company is currently identifying third parties whose business significantly impacts the Company, has contacted some significant third parties to determine the extent to which interfaces with such entities are vulnerable to Year 2000 issues, and will contact others as it completes the identification phase.

In the event that the Company is unable to complete the remediation or replacement of its critical systems, facilities and equipment, establish alternative procedures in a timely manner, or if those with whom the Company conducts business are unsuccessful in implementing timely solutions, Year 2000 issues could have a material adverse effect on the Company's liquidity and results of operations. At this time, the potential effect in the event the Company and/or third parties are unable to timely resolve their Year 2000 problems is not determinable. A contingency plan has not been developed for dealing with the most reasonably likely worst case scenario, and such scenario has not yet been clearly identified. However, the Company currently believes that it will be able to resolve its own Year 2000 issues in a timely manner.

The disclosure set forth in this section is provided pursuant to Securities Act Release No. 33-7558. As such it is protected as a forward-looking statement under the Private Securities Litigation Reform Act of 1995. See "Forward-Looking Statements." This disclosure is also subject to protection under the Year 2000 Information and Readiness Disclosure Act of 1998, Public Law 105-271, as a "Year 2000 Statement" and "Year 2000 Readiness Disclosure" as defined therein.

Recent Accounting Pronouncements

In June 1997, the Financial Accounting Standards Board (the "FASB") issued SFAS No. 130, "Reporting Comprehensive Income" which established standards for reporting, in addition to net income, comprehensive income and its components. Adoption of this standard has no impact on the Company's financial statements.

In June 1997, the FASB issued SFAS No. 131, "Disclosure about Segments of an Enterprise and Related Information," which the Company adopted in the first quarter of 1998. As all of the Company's natural gas and oil properties and related operations are located in the United States, management has determined that the Company has one reportable segment.

In June 1998, the FASB issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," which is effective for fiscal years beginning after June 15, 1999. The Company is currently assessing the impact adoption of this standard will have on its financial statement presentation.

Forward Looking Information

Brigham or its representatives may make forward looking statements, oral or written, including statements in this report, press releases and filings with the SEC, regarding estimated future net revenues from oil and natural gas reserves and the present value thereof, planned capital expenditures (including the amount and nature thereof), increases in oil and gas production, the number of wells the Company anticipates drilling through 1999 and the Company's financial position, business strategy and other plans and objectives for future operations. Although the Company believes that the expectations reflected in these forward looking statements are reasonable, there can be no assurance that the actual results or developments anticipated by the Company will be realized or, even if substantially realized, that they will have the expected effects on its business or operations. Among the factors that could cause actual results to differ materially from the Company's expectations are general economic conditions, inherent uncertainties in interpreting engineering data, operating hazards, delays or cancellations of drilling operations for a variety of reasons, competition, fluctuations in oil and gas prices, the ability of the Company to successfully integrate the business and operations of acquired companies, government regulations and other factors set forth among the risk factors noted below or in the description of the Company's business in Item 1 of this report. All subsequent oral and written forward looking statements attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these factors. The Company assumes no obligation to update any of these statements.

Risk Factors

Effects of Leverage. The Company had long-term debt outstanding of $99 million (principal amount) as of December 31, 1998 and $100.3 million (principal amount) as of March 26, 1999. The Indenture limits the amounts of additional debt borrowings, including borrowings under the Credit Facility or other Senior Indebtedness (as defined). However, the Indenture permits the Company to borrow under the Credit Facility up to the lesser of $75 million or the borrowing base under the Credit Facility ($65 million as of December 31, 1998 and March 26, 1999), which would provide the Company with the ability to borrow up to $6 million of additional indebtedness under its Credit Facility as of December 31, 1998 and March 26, 1999. In addition, the Indenture allows the Company to borrow up to $25 million of future subordinated indebtedness that is *pari passu* in right of payment with the Subordinated Notes if the holders of the Subordinated Notes have been given a first look and right to make a proposal for such subordinated indebtedness.

The Company's level of indebtedness will have several important effects on its operations, including (i) a substantial portion of the Company's cash flow from operations will be dedicated to the payment of interest on its indebtedness and will not be available for other purposes; (ii) the covenants contained in the Credit Facility and the Indenture limit its ability to borrow additional funds or to dispose of assets and may affect the Company's flexibility in planning for, and reacting to, changes in business conditions and (iii) the Company's ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate purposes or other purposes may be impaired. Moreover, future exploration, development or acquisition activities may require the Company to alter its capitalization significantly. These changes in capitalization may significantly alter the leverage of the Company. The Company's ability to meet its debt service obligations and to reduce its total indebtedness will be dependent upon the Company's future performance, which will be subject to general economic conditions and to financial, business and other factors affecting the operations of the Company, many of which are beyond its control. There can be no assurance that the Company's future performance will not be adversely affected by such economic conditions and financial, business and other factors. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity" and "— Capital Resources."

Substantial Capital Requirements; Limited Current Liquidity. The Company makes and will continue to make substantial capital expenditures in its exploration and development projects. The Company's available capital resources at March 26, 1999 are limited and not sufficient to fund its planned working capital needs and capital expenditures for 1999. The Company intends to finance these working capital needs and planned capital expenditures with cash flow from operations, borrowings available under the Credit Facility, the potential sales of interests in certain producing properties and 3-D seismic projects and the potential issuance of additional equity securities. Additional financing will be required in the future to fund the Company's exploratory and developmental drilling and 3-D seismic acquisition activities at currently budgeted levels. No assurance can be given as to the availability or terms of any such additional financing that may be required or that financing will continue to be available under the existing or new financing arrangements. If additional capital resources are not available to the Company, its drilling and other activities may be curtailed and its business, financial condition and results of operations could be materially adversely affected. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity" and " — Capital Resources."

Dependence on Exploratory Drilling Activities. The Company's revenues, operating results and future rate of growth are highly dependent upon the success of its exploratory drilling program. Exploratory drilling involves numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be encountered. The cost of drilling, completing and operating wells is often uncertain, and drilling operations may be curtailed, delayed or canceled 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. Despite the use of 3-D seismic and other advanced technologies, exploratory drilling remains a speculative activity. Even when fully utilized and properly interpreted, 3-D seismic data and other advanced technologies only assist geoscientists in identifying subsurface structures and do not enable the interpreter to know whether hydrocarbons are in fact present in those structures. In addition, the use of 3-D seismic data and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and the Company could incur losses as a result of such expenditures. The Company's future drilling activities may not be successful. There can be no assurance that the Company's overall drilling success rate or its drilling success rate for activity within a particular province will not decline. Unsuccessful drilling activities could have a material adverse effect on the Company's results of operations and financial condition. The Company often gathers 3-D seismic data over large areas. The Company's interpretation of data delineates those portions of an area desirable for drilling. Therefore, the Company may choose not to acquire option and lease rights prior to acquiring seismic and, in many cases, the Company may identify a drilling location before seeking option or lease rights in the location. Although the Company has identified numerous potential drilling locations, there can be no assurance that they will ever be leased or drilled or that natural gas or oil will be produced from these or any other potential drilling locations.

Volatility of Oil and Natural Gas Prices. The Company's revenues, operating results and future rate of growth are highly dependent upon the prices received for the Company's oil and natural gas. Historically, the markets for oil and natural gas have been volatile and are likely to continue to be volatile in the future. Various factors beyond the control of the Company will affect prices of its oil and natural gas, 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. During 1998, the high and low prices for oil on the NYMEX were $17.82 per Bbl and $10.72 per Bbl, and the high and low prices for natural gas on the NYMEX were $2.69 per MMBtu and $1.65 per MMBtu. The recent decline in oil prices is generally thought to be caused primarily by an oversupply of worldwide crude oil inventory created, in part, by unusually warm winters in the United States and Europe in 1997 and 1998, an announced increase in crude oil production quotas for OPEC countries in late 1997 and a possible decline in demand in certain Asian markets. The recent decline in natural gas prices is generally thought to be caused primarily by an oversupply of domestic natural gas inventory created, in part, by reduced demand for natural gas due to unusually warm winters in the United States in 1997 and 1998. It is impossible to predict future oil and natural gas price movements with certainty. If such declines in the NYMEX crude oil or natural gas prices worsen or persist for a protracted period, it would adversely affect the Company's revenues, net income and cash flows from operations. Also, if these prices maintain their present level for an extended time period or decline further, the Company may delay or postpone certain of its capital projects. Declines in oil and natural gas prices may materially adversely affect the Company's financial condition, liquidity, ability to finance planned capital expenditures and results of operations. Lower oil and natural gas prices also may reduce the amount of oil and natural gas that the Company can produce economically. Any significant decline in the price of natural gas or oil would adversely affect the Company's revenues and operating income and may require a reduction in the carrying value of the Company's oil and natural gas properties. See "Item 1. Business — Competition" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations".

Historical Operating Losses and Variability of Operating Results. The Company had net losses of approximately $1.3 million in 1994, $1.6 million in 1995, $450,000 in 1996, $1.1 million (including a net $1.2 million non-cash deferred income tax charge incurred in connection with the Company's conversion from a partnership to a corporation) in 1997, and $33.3 million (including a $24.8 million non-cash writedown in the carrying value of its natural gas and oil properties) in 1998. The Company has incurred net losses in each year of operation, and there can be no assurance that the Company will be profitable in the future. At December 31, 1998, the Company's accumulated earnings were a deficit of $33.4 million and its total stockholders' equity was $24.7 million. In addition, the Company's 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, rates of production from completed wells and the timing and amount of capital expenditures. This variability could have a material adverse effect on the Company's business, financial condition and results of operations. In addition, any failure or delay in the realization of expected cash flows from operating activities could limit the Company's ability to invest and participate in economically attractive projects. See "Item 6. Selected Financial Data" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

Reserve Replacement Risk. 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 the Company conducts successful exploration and development activities or acquires properties containing proved reserves, or both, the proved reserves of the Company will decline as reserves are produced. The Company's future oil and natural gas production is highly dependent upon its ability to economically find, develop or acquire reserves in commercial quantities. The business of exploring for or developing reserves is capital intensive. To the extent cash flow from operations is reduced and external sources of capital become limited or unavailable, the Company's ability to make the necessary capital investment to maintain or expand its asset base of oil and natural gas reserves would be impaired. The Company participates in a percentage of its wells as a non-operator. The failure of an operator of the Company's wells to adequately perform operations, or an operator's breach of the applicable agreements, could adversely impact the Company. In addition, there can be no assurance that the Company's future exploration and development activities will result in additional proved reserves or that the Company will be able to drill productive wells at acceptable costs. Furthermore, although the Company's revenues could increase if prevailing prices for oil and natural gas increase significantly, the Company's finding and development costs could also increase. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

Operating Hazards and Uninsured Risks. The Company's 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 properties of the Company and others. As protection against operating hazards, the Company maintains insurance coverage against some, but not all, potential losses. The Company may elect to self-insure if management believes that the cost of insurance, although available, is excessive relative to the risks presented. The Company generally maintains insurance for the hazards and risks inherent in drilling for and producing and transporting oil and natural gas and believes this insurance is adequate. Nevertheless, the occurrence of an event that is not covered, or not fully covered, by insurance could have a material adverse effect on the Company's financial condition and results of operations. In addition, pollution and environmental risks generally are not fully insurable. See "Item 2. Business and Properties — Operating Hazards and Uninsured Risks" and "

Uncertainty of Reserve Information and Future Net Revenue Estimates. Numerous uncertainties are inherent in estimating quantities of proved reserves and their values, including many factors beyond the Company's control. The reserve information in herein is an estimate only. Although the Company believes these estimates are reasonable, reserve estimates are imprecise and are expected to change as additional information becomes available. Estimates of oil and natural gas reserves by necessity are projections based on engineering data, and uncertainties are inherent in the interpretation of this data, the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geologic interpretation, and judgment. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies, and assumptions concerning future oil and natural gas prices, future operating costs, severance and excise taxes, development costs and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of reserves based on risk of recovery, and estimates of the future net cash flows may vary substantially. Moreover, there can be no assurance that the Company's reserves will ultimately be produced or that the Company's proved undeveloped reserves will be developed within the periods anticipated. Any significant variance in the assumptions could materially affect the estimated quantity and value of the Company's reserves. Actual production, revenues and expenditures with respect to the Company's reserves will likely vary from estimates, and such variances may be material. See "Item 2. Business and Properties — Oil and Natural Gas Reserves."

The Present Value of Future Net Revenues referred to herein should not be construed as the current market value of the estimated oil and natural gas reserves attributable to the Company's properties. In accordance with applicable requirements of the SEC, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the date of the estimate, whereas actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as the amount and timing of actual production, supply and demand for oil and natural gas, curtailments or increases in consumption by gas purchasers, and changes in governmental regulations or taxation. The timing of actual future net cash flows from proved reserves, and thus their actual present value, will be affected by the timing of both the production and the incurrence of expenses in connection with development and production of oil and natural gas properties. In addition, the 10% discount factor, which must be used to calculate discounted future net cash flows for SEC reporting purposes, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Company or the oil and gas industry in general.

Competition. The Company operates in the highly competitive areas of oil and natural gas exploration, exploitation, acquisition and production with other companies. In seeking to acquire desirable producing properties or new leases for future exploration and in marketing its oil and natural gas production, as well as in seeking to acquire the equipment and expertise necessary to operate and develop those properties, the Company faces intense competition from a large number of independent, technology-driven companies as well as both major and other independent oil and natural gas companies. Many of these competitors have financial and other resources substantially in excess of those available to the Company. The effects of this highly competitive environment could have a material adverse effect on the Company. See "Item 1. Business — Competition."

Compliance with Government Regulations. The Company's business is subject to federal, state and local laws and regulations relating to the exploration for, and the development, production and marketing of, oil and natural gas, as well as safety matters. Although the Company believes it is in substantial compliance with all applicable laws and regulations, legal requirements are frequently changed and subject to interpretation, and the Company is unable to predict the ultimate cost of compliance with these requirements or their effect on its operations. Significant expenditures may be required to comply with governmental laws and regulations. See "Item 1. Business — Governmental Regulation."

Compliance with Environmental Regulations. The Company's operations are subject to complex environmental laws and regulations adopted by federal, state and local governmental authorities. Environmental laws and regulations are frequently changed. The implementation of new, or the modification of existing, laws or regulations could have a material adverse effect on the Company. The discharge of natural gas, oil, or other pollutants into the air, soil or water may give rise to significant liabilities on the part of the Company to the government and third parties and may require the Company to incur substantial costs of remediation. No assurance can be given that existing environmental laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations will not materially adversely affect the Company's results of operations and financial condition. See "Item 1. Business — Environmental Matters."

Risk of Hedging Activities. In an attempt to reduce its sensitivity to energy price volatility, the Company uses swap arrangements that generally result in a fixed price over a period of six to eighteen months. If the Company's reserves are not produced at rates equivalent to the hedged position, the Company would be required to satisfy its obligations under hedging contracts on potentially unfavorable terms without the ability to hedge that risk through sales of comparable quantities of its own production. Further, the terms under which the Company enters into hedging contracts are based on assumptions and estimates of numerous factors such as cost of production and pipeline and other transportation costs to delivery points. Substantial variations between the assumptions and estimates used by the Company and actual results experienced could materially adversely affect the Company's anticipated profit margins and its ability to manage the risk associated with fluctuations in oil and natural gas prices. Additionally, hedging contracts limit the benefits the Company will realize if actual prices rise above the contract prices. In addition, hedging contracts are subject to the risk that the other party may prove unable or unwilling to perform its obligations under such contracts. Any significant nonperformance could have a material adverse financial effect on the Company. For the year ended December 31, 1998, the Company realized an increase in revenues attributable to natural gas hedges of $555,240. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Other Matters — Hedging Activities" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Marketability of Production. The marketability of the Company's production depends in part upon the availability, proximity and capacity of natural gas gathering systems, pipelines and processing facilities. The Company generally delivers natural gas through gas gathering systems and gas pipelines that it does not own. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand and general economic conditions all could adversely affect the Company's ability to produce and market its oil and natural gas. Any dramatic change in market factors could have a material adverse effect on the Company.

Dependence on Key Personnel. The Company has assembled a team of geologists, geophysicists and engineers having considerable experience applying 3-D imaging technology. The Company is dependent upon the knowledge, skills and experience of these experts to provide 3-D imaging and assist the Company in reducing the risks associated with its participation in oil and natural gas exploration projects. In addition, the success of the Company's business also depends to a significant extent upon the abilities and continued efforts of its management, particularly Ben M. Brigham, the Company's Chief Executive Officer, President and Chairman of the Board. The Company has an employment agreement with Ben M. Brigham, but does not have an employment agreement with any of its other employees. The Company has key man life insurance on Mr. Brigham in the amount of $2 million. The loss of services of key management personnel or the Company's technical experts, or the inability to attract additional qualified personnel, could have a material adverse effect on the Company's business, financial condition, results of operations, development efforts and ability to grow. There can be no assurance that the Company will be successful in attracting and retaining such executives, geophysicists, geologists and engineers. See "Item 1. Business — Exploration Staff" and "Executive Officers of the Registrant".

Control by Existing Stockholders. As of March 26, 1999, directors, executive officers and principal stockholders of the Company, and certain of their affiliates, beneficially owned approximately 63% of the Company's 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 the Company's 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 make it unlikely that any other holder of Common Stock will be able to affect the management or direction of the Company. These factors may also have the effect of delaying or preventing a change in the management or voting control of the Company.

Certain Antitakeover Considerations. The Company's Certificate of Incorporation authorizes the Board of Directors of the Company to issue up to 10 million shares of preferred stock without stockholder approval and to set the rights, preferences and other designations, including voting rights, of those shares as the Board of Directors may determine. These provisions, alone or in combination with the matters described in "Risk Factors — Control by Existing Stockholders," may discourage transactions involving actual or potential changes of control of the Company, including transactions that otherwise could involve payment of a premium over prevailing market prices to holders of Common Stock. The Company also is subject to provisions of the Delaware General Corporation Law that may make some business combinations more difficult.

Year 2000 Compliance. Many computer software systems, as well as certain hardware and equipment using date-sensitive data, were structured to use a two-digit date field meaning that they may not be able to properly recognize dates in the year 2000. The Company currently expects that any costs necessary for the Company to become Year 2000 compliant will not have a material adverse effect on the Company's financial condition, operations or liquidity. However, the Company cannot reasonably estimate the potential impact on its financial condition and operations if key third parties including, among others, suppliers, contractors, joint venture partners, financial institutions, customers and governments do not become Year 2000 compliant on a timely basis. There can be no assurance that the Company will be able to complete any necessary remediation or replacement of its critical systems, facilities and equipment or establish alternative procedures in a timely manner; that those with whom the Company conduct business will be successful in implementing timely solutions; or that Year 2000 issues will not have a material adverse effect on the Company's business, financial position and results of operations. See "Item 7. Management's Discussion and Analysis of Financial Conditions and Result of Operations — Other Matters — Year 2000 Issues".

Possible Stock Price Volatility. The trading price of the Common Stock and the price at which the Company may sell securities in the future could be subject to large fluctuations in response to limited trading volume in the Company's stock and changes in government regulations, quarterly variations in operating results, litigation, general market conditions, the prices of natural gas and oil, announcements by the Company and its competitors, the liquidity of the Company, the Company's ability to raise additional funds and other events.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Management Opinion Concerning Derivative Instruments

The Company limits its use of derivative instruments principally to commodity price hedging activities, whereby gains and losses are generally offset by price changes in the underlying commodity. As a result, management believes that its use of derivative instruments does not expose the Company to material risk. The Company's use of derivative instruments for hedging activities could materially affect the Company's results of operations in particular quarterly or annual periods since such instruments can limit the Company's ability to benefit from favorable oil and natural gas price movements. However, management believes that use of these instruments will not have a material adverse effect on the Company's financial position or liquidity.

Commodity Price Risk

The Company's primary commodity market risk exposure is to changes in the prices related to the sale of its oil and natural gas production. The market prices for oil and natural gas have been volatile and are likely to continue to be volatile in the future. As such, the Company employs established policies and procedures to manage its exposure to fluctuations in the sales prices it receives for its oil and natural gas production through hedging activities. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Other Matters — Hedging Activities."

The Company believes that hedging, although not free of risk, allows the Company to reduce its exposure to oil and natural gas sales price fluctuations and thereby to achieve more predictable cash flows. However, hedging arrangements, when utilized, limit the benefit to the Company of increases in the prices of the hedged commodity. Moreover, the Company's hedging arrangements apply only to a portion of its production and provide only partial price protection against declines in commodity prices. The Company expects that the amount of its hedges will vary from time to time.

Based on the Company's natural gas swap arrangements outstanding at December 31, 1998, an adverse change (defined as a hypothetical 10% and 25% increase in underlying commodity prices for open positions) would lower revenue and income before taxes by approximately $902,000 and $2.3 million, respectively, from currently projected levels. Additionally, as the Company utilizes swap arrangements to hedge anticipated and firmly committed transactions, a loss in fair value for those instruments is generally offset by price changes in the underlying commodity. The impact of these price changes are not reflected in this sensitivity analysis.

Interest Rate Risk

The Company does not utilize derivative instruments to protect against changes in interest rates on debt borrowings. See Note 11 of Notes to Consolidated Financial Statements for a description of the Company's financial instruments at December 31, 1998.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The Company's Consolidated Financial Statements required by this item are included on the pages immediately following the Index to Financial Statements appearing on page F1-1.

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

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required by this item is incorporated by reference to information under the caption "Proposal 1) Election of Directors" and to the information under the caption "Compliance with Section 16(a) of the Securities Exchange Act of 1934" in the Company's definitive Proxy Statement (the "1999 Proxy Statement") for its annual meeting of stockholders to be held on May 13, 1999. The 1999 Proxy Statement will be filed with the Securities and Exchange Commission (the "Commission") not later than 120 days subsequent to December 31, 1998.

Pursuant to Item 401(b) of Regulation S-K, the information required by this item with respect to executive officers of the Company 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 1999 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 1998.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by this item is incorporated herein by reference to the 1999 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 1998.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

The information required by this item is incorporated herein by reference to the 1999 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 1998.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) 1. Consolidated Financial Statements:

See Index to Consolidated Financial Statements on page F-1.

2. Financial Statement Schedules:

See Index to Consolidated Financial Statements on page F-1.

3. Exhibits: The following documents are filed as exhibits to this report:

Number		Description
2.1	—	Exchange Agreement (filed as Exhibit 2.1 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
3.1	—	Certificate of Incorporation (filed as Exhibit 3.1 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
3.2	—	Bylaws (filed as Exhibit 3.2 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
4.1	—	Form of Common Stock Certificate (filed as Exhibit 4.1 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
4.2+	—	Indenture dated as of August 20, 1998 between Brigham Exploration Company and Chase Bank of Texas, National Association, as Trustee.
4.2.1++	—	Supplemental Indenture dated as of March 26, 1999 between Brigham Exploration Company and Chase Bank of Texas, National Association, as Trustee.
4.3++	—	Form of Warrant Certificate.
4.4	—	Form of Senior Subordinated Secured Note due 2003 (filed as Exhibit 4.4 to the Company's Registration Statement on Form S-1 (Registration No. 333-53873), and incorporated herein by reference).
10.1	—	Agreement of Limited Partnership, dated May 1, 1992, between Brigham Exploration Company and General Atlantic Partners III, L.P. as general partners, and Harold D. Carter and GAP-Brigham Partners, L.P. as limited partners (filed as Exhibit 10.1 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.1.1	—	Amendment No. 1 to Agreement of Limited Partnership of Brigham Oil & Gas, L.P., dated May 1, 1992, by and among Brigham Exploration Company, General Atlantic Partners III, L.P., GAP-Brigham Partners, L.P. and Harold D. Carter (filed as Exhibit 10.1.1 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.1.2	—	Amendment No. 2 to Agreement of Limited Partnership of Brigham Oil & Gas, L.P., dated September 30, 1994, by and among Brigham Exploration Company, General Atlantic Partners III, L.P., GAP-Brigham Partners, L.P., Harold D. Carter and the additional signatories thereto (filed as Exhibit 10.1.2 to the Company's Registration

Number		Description
		Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.1.3	—	Amendment No. 3 to Agreement of Limited Partnership of Brigham Oil & Gas, L.P., dated August 24, 1995, by and among Brigham Exploration Company, General Atlantic Partners III, L.P., GAP-Brigham Partners, L.P., Harold D. Carter, Craig M. Fleming, David T. Brigham and Jon L. Glass (filed as Exhibit 10.1.3 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.1.4+	—	Amended and Restated Agreement of Limited Partnership of Brigham Oil & Gas, L.P., dated December 30, 1997 by and among Brigham, Inc., Brigham Holdings I, L.L.C. and Brigham Holdings II, L.L.C.
10.2	—	Agreement of Limited Partnership of Venture Acquisitions, L.P., dated September 23, 1994, by and between Quest Resources, L.L.C. and RIMCO Energy, Inc. as general partners, and RIMCO Production Company, Inc., RIMCO Exploration Partners, L.P. I and RIMCO Exploration Partners, L.P. II, as limited partners (filed as Exhibit 10.2 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.3	—	Regulations of Quest Resources, L.L.C. (filed as Exhibit 10.3 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.4	—	Management and Ownership Agreement, dated September 23, 1994, by and among Brigham Oil & Gas, L.P., Brigham Exploration Company, General Atlantic Partners III, L.P., Harold D. Carter, Ben M. Brigham and GAP-Brigham Partners, L.P. (filed as Exhibit 10.4 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.5*	—	Consulting Agreement, dated May 1, 1997, by and between Brigham Oil & Gas, L.P. and Harold D. Carter (filed as Exhibit 10.4 to the Company's Registration Statement on Form S-1 (Registration No. 33-53873), and incorporated herein by reference).
10.6*	—	Employment Agreement, by and between Brigham Exploration Company and Ben M. Brigham (filed as Exhibit 10.7 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.7*	—	Form of Confidentiality and Noncompete Agreement between the Registrant and each of its executive officers (filed as Exhibit 10.8 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.8*	—	1997 Incentive Plan of Brigham Exploration Company (filed as Exhibit 10.9 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.8.1*	—	Form of Option Agreement for certain executive officers (filed as Exhibit 10.9.1 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.8.2*	—	Option Agreement dated as of March 4, 1997, by and between Brigham Exploration Company and Jon L. Glass (filed as Exhibit 10.9.2 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.9*	—	Incentive Bonus Plan dated as of February 28, 1997 of Brigham, Inc. and Brigham Oil & Gas, L.P. (filed as Exhibit 10.10 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.10	—	Two Bridgepoint Lease Agreement, dated September 30, 1996, by and between Investors Life Insurance Company of North America and Brigham Oil & Gas, L.P. (filed as Exhibit 10.14 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).

Number		Description
10.10.1	—	First Amendment to Two Bridge Point Lease Agreement dated April 11, 1997 between Investors Life Insurance Company of North America and Brigham Oil & Gas, L.P. (filed as Exhibit 10.9.1 to the Company's Registration Statement on Form S-1 (Registration No. 333-53873), and incorporated herein by reference).
10.10.2	—	Second Amendment to Two Bridge Point Lease Agreement dated October 13, 1997 between Investors Life Insurance Company of North America and Brigham Oil & Gas, L.P. (filed as Exhibit 10.9.2 to the Company's Registration Statement on Form S-1 (Registration No. 333-53873), and incorporated herein by reference).
10.10.3	—	Letter dated April 17, 1998 exercising Right of First Refusal to Lease "3rd Option Space" (filed as Exhibit 10.9.3 to the Company's Registration Statement on Form S-1 (Registration No. 333-53873), and incorporated herein by reference).
10.11	—	Anadarko Basin Seismic Operations Agreement, dated February 15, 1996, by and between Brigham Oil & Gas, L.P. and Veritas Geophysical, Ltd. (filed as Exhibit 10.15 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.11.1	—	Letter Amendment to Anadarko Basin Seismic Operations Agreement, dated June 10, 1996, between Brigham Oil & Gas, L.P. and Veritas Geophysical, Ltd. (filed as Exhibit 10.15.1 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.12	—	Expense Allocation and Participation Agreement, dated April 1, 1996, between Brigham Oil & Gas, L.P. and Gasco Limited Partnership. (filed as Exhibit 10.16 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.12.1	—	Amendment to Expense Allocation and Participation Agreement, dated October 21, 1996, between Brigham Oil & Gas, L.P. and Gasco Limited Partnership (filed as Exhibit 10.16.1 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.13	—	Expense Allocation and Participation Agreement, dated April 1, 1996, between Brigham Oil & Gas, L.P. and Middle Bay Oil Company, Inc. (filed as Exhibit 10.17 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.13.1	—	Amendment to Expense Allocation and Participation Agreement, dated September 26, 1996, between Brigham Oil & Gas, L.P. and Middle Bay Oil Company, Inc. (filed as Exhibit 10.17.1 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.13.2	—	Letter Amendment to Expense Allocation and Participation Agreement, dated May 20, 1996, between Brigham Oil & Gas, L.P. and Middle Bay Oil Company, Inc. (filed as Exhibit 10.17.2 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.14	—	Anadarko Basin Joint Participation Agreement, dated May 1, 1996, by and among Stephens Production Company and Brigham Oil & Gas, L.P. (filed as Exhibit 10.18 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.15	—	Anadarko Basin Joint Participation Agreement, dated May 1, 1996, by and between Vintage Petroleum, Inc. and Brigham Oil & Gas, L.P. (filed as Exhibit 10.19 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.16	—	Processing Alliance Agreement, dated July 20, 1993, between Veritas Seismic Ltd. and Brigham Oil & Gas, L.P. (filed as Exhibit 10.20 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).

Number		Description
10.16.1	—	Letter Amendment to Processing Alliance Agreement, dated November 3, 1994, between Veritas Seismic Ltd. and Brigham Oil & Gas, L.P. (filed as Exhibit 10.20.1 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.17	—	Agreement and Assignment of Interest, West Bradley Project, dated September 1, 1995, by and between Aspect Resources Limited Liability Company and Brigham Oil & Gas, L.P. (filed as Exhibit 10.21 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.18	—	Agreement and Assignment of Interests in lands located in Grady County, Oklahoma, West Bradley Project, dated December 1, 1995, by and between Aspect Resources Limited Liability Company, Brigham Oil & Gas, L.P. and Venture Acquisitions, L.P. (filed as Exhibit 10.22 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.19	—	Agreement and Assignment of Interests, West Bradley Project, dated December 1, 1995, by and between Aspect Resources Limited Liability Company and Brigham Oil & Gas, L.P. (filed as Exhibit 10.23 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.20	—	Geophysical Exploration Agreement, Hardeman Project, Hardeman and Wilbarger Counties, Texas and Jackson County, Oklahoma, dated March 15, 1993 by and among General Atlantic Resources, Inc., Maynard Oil Company, Ruja Muta Corporation, Tucker Scully Interests Ltd., JHJ Exploration, Ltd., Cheyenne Petroleum Company, Antrim Resources, Inc., and Brigham Oil & Gas, L.P. (filed as Exhibit 10.24 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.21	—	Agreement and Partial Assignment of Interests in OK13-P Prospect Area, Jackson County, Oklahoma (Hardeman Project), dated August 1, 1995, by and between Brigham Oil & Gas, L.P. and Aspect Resources Limited Liability Company (filed as Exhibit 10.25 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.22	—	Agreement and Partial Assignment of Interests in Q140-E Prospect Area, Hardeman County, Texas (Hardeman Project), dated August 1, 1995, by and between Brigham Oil & Gas, L.P. and Aspect Resources Limited Liability Company (filed as Exhibit 10.26 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.23	—	Agreement and Partial Assignment of Interests in Hankins #1 Chappel Prospect Agreement, Jackson County, Oklahoma (Hardeman Project), dated March 21, 1996, by and between Brigham Oil & Gas, L.P., NGR, Ltd. and Aspect Resources Limited Liability Company (filed as Exhibit 10.27 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.24	—	Form of Indemnity Agreement between the Registrant and each of its executive officers (filed as Exhibit 10.28 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.25	—	Registration Rights Agreement dated February 26, 1997 by and among Brigham Exploration Company, General Atlantic Partners III L.P., GAP-Brigham Partners, L.P., RIMCO Partners, L.P. II, RIMCO Partners L.P. III, and RIMCO Partners, L.P. IV, Ben M. Brigham, Anne L. Brigham, Harold D. Carter, Craig M. Fleming, David T. Brigham and Jon L. Glass (filed as Exhibit 10.29 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).

Number		Description
10.26	—	1997 Director Stock Option Plan (filed as Exhibit 10.30 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.27	—	Form of Employee Stock Ownership Agreement (filed as Exhibit 10.31 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.28	—	Agreement and Assignment of Interest in Geophysical Exploration Agreement, Esperson Dome Project, dated November 1, 1994, by and between Brigham Oil & Gas, L.P. and Vaquero Gas Company (filed as Exhibit 10.33 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.29	—	Geophysical Exploration Agreement, Southwest Danbury Project, Brazoria County, Texas, dated as of July 1, 1996, by and among UNEXCO, Inc. and Brigham Oil & Gas, L.P. (filed as Exhibit 10.34 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.30	—	Geophysical Exploration Agreement, Welder Project, Duval County, Texas, dated as of October 1, 1996, by and among UNEXCO, Inc. and Brigham Oil & Gas, L.P. (filed as Exhibit 10.35 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.31	—	Proposed Trade Structure, RIMCO/Tigre Project, Vermillion Parish, Louisiana, among Brigham Oil & Gas, L.P., Tigre Energy Corporation and Resource Investors Management Company (filed as Exhibit 10.36 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.31.1	—	Letter relating to Proposed Trade Structure, RIMCO/Tigre Project, dated January 31, 1997, from Resource Investors Management Company to Brigham Oil & Gas, L.P. (filed as Exhibit 10.36 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.32	—	Anadarko Basin Seismic Operations Agreement II, dated as of April 1, 1997, by and between Brigham Oil & Gas, L.P. (filed as Exhibit 10.37 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.32.1	—	Letter Amendment to Anadarko Basin Seismic Operations Agreement II, dated March 20, 1997, between Brigham Oil & Gas, L.P. and Veritas DGC Land, Inc. (filed as Exhibit 10.37 to the Company's Registration Statement on Form S-1 (Registration No. 333-22491), and incorporated herein by reference).
10.33	—	Expense Allocation and Participation Agreement II, dated April 1, 1997, between Brigham Oil & Gas, L.P., and Gasco Limited Partnership (filed as Exhibit 10.31 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 1997, and incorporated herein by reference).
10.36	—	Credit Agreement dated as of January 26, 1998 among Brigham Oil & Gas, L.P., Bank of Montreal, as Agent, and the lenders signatory thereto (filed as Exhibit 10.36 to the Company's Annual Report on Form 10-K for the year ended December 31, 1997, and incorporated herein by reference).
10.36.1+	—	First Amendment to Credit Agreement dated as of August 20, 1998 among Brigham Oil & Gas, L.P., Bank of Montreal, as Agent, and the lenders signatory thereto.
10.36.2++	—	Second Amendment to Credit Agreement dated as of March 26, 1999 among Brigham Oil & Gas, L.P., Bank of Montreal, as Agent, and the lenders signatory thereto.

Number		Description
10.37	—	Guaranty Agreement dated January 26, 1998 by Brigham Exploration Company in favor of Bank of Montreal, as Agent, and each of the Lenders party to the Credit Agreement (filed as Exhibit 10.33.1 to the Company's Registration Statement on Form S-1 (Registration No. 333-53873), and incorporated herein by reference).
10.37.1	—	First Amendment to Guaranty Agreement dated as of March 30, 1998 between Brigham Exploration Company and Bank of Montreal, as Agent for the Lenders party to the Credit Agreement (filed as Exhibit 10.33.2 to the Company's Registration Statement on Form S-1 (Registration No. 333-53873), and incorporated herein by reference).
10.37.2+	—	Second Amendment to Guaranty Agreement dated as of August 20, 1998 between Brigham Exploration Company and Bank of Montreal, as Agent for the Lenders party to the Credit Agreement.
10.37.3++	—	Third Amendment to Guaranty Agreement dated as of March 26, 1999 between Brigham Exploration Company and Bank of Montreal, as Agent for the Lenders party to the Credit Agreement.
10.38+	—	Securities Purchase Agreement dated as of August 20, 1998 among Brigham Exploration Company, Enron Capital & Trade Resources Corp. and Joint Energy Development Investments II Limited Partnership.
10.39+	—	Registration Rights Agreement dated as of August 20, 1998, by and among Brigham Exploration Company, Enron Capital & Trade Resources Corp. and Joint Energy Development Investments II Limited Partnership.
10.39.1++	—	Amendment to Registration Rights Agreement dated as of March 26, 1999, by and among Brigham Exploration Company, Enron Capital & Trade Resources Corp., ECT Merchant Investments Corp. and Joint Energy Development Investments II Limited Partnership.
10.40+	—	Form of Guaranty for subsidiaries.
10.41++	—	Exchange Agreement dated as of March 30, 1999 by and between Brigham Exploration Company and Veritas DGC Land, Inc.
10.42++	—	Registration Rights Agreement dated as of March 30, 1999 by and between Brigham Exploration Company and Veritas DGC Land, Inc.
21+	—	Subsidiaries of the Registrant.
23.1+	—	Consent of Price Waterhouse LLP, independent public accountants.
23.2+	—	Consent of Cawley, Gillespie & Associates, Inc., independent petroleum engineers.
27+	—	Financial Data Schedule.

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* Management contract or compensatory plan.

\+ Filed herewith

++ Not filed herewith pursuant to Rule 12b-25 under the Act, and to be filed by amendment.

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

None.

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.

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

Bcf. One billion cubic feet.

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

CAEX. Computer-aided exploration.

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

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

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

Drilling Costs. The costs associated with drilling and completing a well (exclusive of seismic and land acquisition costs for that well and future development costs associated with proved undeveloped reserves added by the well) divided by total proved reserve additions.

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

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

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

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

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

Mcf. One thousand cubic feet of natural gas.

Mcfe. One thousand cubic feet of natural gas equivalents.

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

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

MMcf. One million cubic feet of natural gas.

MMcfe. One million cubic feet of natural gas equivalents.

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

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

Oil. Crude oil, condensate or other liquid hydrocarbons.

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

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

Proved Developed 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.

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

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

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

Success 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.

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

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

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, hereunder duly authorized, as of March 31, 1999.

BRIGHAM EXPLORATION COMPANY

By: /s/ Ben M. Brigham
Ben M. Brigham
Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below as of March 31, 1999, by the following persons on behalf of the Registrant and in the capacity indicated.

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

/s/ Jon L. Glass
Jon L. Glass
Vice President - Exploration and Director

/s/ Craig M. Fleming
Craig M. Fleming
Chief Financial Officer
(principal financial and accounting officer)

/s/ Anne L. Brigham
Anne L. Brigham
Director

/s/ Harold D. Carter
Harold D. Carter
Director

/s/ W. Craig Childers
W. Craig Childers
Director

/s/ Alexis M. Cranberg
Alexis M. Cranberg
Director

/s/ Stephen P. Reynolds
Stephen P. Reynolds
Director

INDEX TO FINANCIAL STATEMENTS

As all Brigham Exploration Company subsidiaries fully and unconditionally guarantee the Senior Subordinated Secured Notes and the Company has no significant assets other than its investments in its subsidiaries, the consolidated financial statements are substantially the same as the financial statements of the subsidiary guarantors and separate financial statements have been omitted as they would not be meaningful to investors.

Financial statements for the wholly owned subsidiaries whose securities are pledged as collateral for the Senior Subordinated Notes are included in the combined financial statements.*

*These items are omitted from this Form 10-K pursuant to Rule 12b-25 under the Act and will be filed by amendment to this Form 10-K.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors
and Stockholders of Brigham Exploration Company

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations and changes in stockholders' equity and of cash flows, after the restatement discussed in Note 12, present fairly, in all material respects, the financial position of Brigham Exploration Company and its subsidiaries at December 31, 1998 and 1997, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998, in conformity with generally accepted accounting principles. 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 generally accepted auditing standards 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 the opinion expressed above.

PricewaterhouseCoopers LLP

Houston, Texas
March 30, 1999

BRIGHAM EXPLORATION COMPANY

CONSOLIDATED BALANCE SHEETS

(in thousands)

	December 31, 1998	December 31, 1997
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,569	$ 1,701
Accounts receivable	7,938	4,909
Prepaid expenses	290	280
Total current assets	10,797	6,890
Natural gas and oil properties, at cost, net	134,317	84,294
Other property and equipment, at cost, net	2,014	1,239
Drilling advances paid	230	78
Other noncurrent assets	3,158	18
	$ 150,516	$ 92,519
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 19,883	$ 11,892
Accrued drilling costs	1,219	2,406
Participant advances received	764	489
Other current liabilities	1,647	726
Total current liabilities	23,513	15,513
Notes payable	59,000	32,000
Senior subordinated notes, net	35,786	-
Other noncurrent liabilities	7,536	507
Deferred income tax liability	-	1,186
Stockholders' equity:		
Preferred stock, $.01 par value, 10 million shares authorized, none issued and outstanding	-	-
Common stock, $.01 par value, 30 million shares authorized, 13,306,206 and 12,253,574 issued and outstanding at December 31, 1998 and 1997, respectively	133	123
Additional paid-in capital	58,838	44,919
Unearned stock compensation	(890)	(1,674)
Accumulated deficit	(33,400)	(55)
Total stockholders' equity	24,681	43,313
	$ 150,516	$ 92,519

The Company uses the full cost method to account for its natural gas and oil properties.

See accompanying notes to the consolidated financial statements.

BRIGHAM EXPLORATION COMPANY

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

	Year Ended December 31, 1998	1997	1996
Revenues:			
Natural gas and oil sales	$ 13,799	$ 9,184	$ 6,141
Workstation revenue	390	637	627
	14,189	9,821	6,768
Costs and expenses:			
Lease operating	2,172	1,151	726
Production taxes	850	549	362
General and administrative	4,672	3,570	2,199
Depletion of natural gas and oil properties	8,410	2,743	2,323
Depreciation and amortization	413	306	487
Capitalized ceiling impairment	24,847	-	-
Amortization of stock compensation	372	388	-
	41,736	8,707	6,097
Operating income (loss)	(27,547)	1,114	671
Other income (expense):			
Interest income	136	145	52
Interest expense	(7,120)	(1,017)	(373)
Interest expense - related party	-	(173)	(800)
	(6,984)	(1,045)	(1,121)
Net income (loss) before income taxes	(34,531)	69	(450)
Income tax benefit (expense)	1,186	(1,186)	-
Net loss	$ (33,345)	$ (1,117)	$ (450)
Net loss per share:			
Basic/Diluted	$ (2.64)	$ (0.10)	$ (0.05)
Common shares outstanding:			
Basic/Diluted	12,626	11,081	8,929
Unaudited pro forma information (Notes 1 and 2)			
Net loss			$ (450)
Pro forma Exchange adjustments			275
Pro forma net loss before income taxes			(175)
Pro forma income tax benefit			97
Pro forma net loss			$ (78)
Pro forma net loss per basic/diluted common share			$ (0.01)
Pro forma weighted average number of common basic/diluted shares outstanding			9,170

See accompanying notes to the consolidated financial statements.

BRIGHAM EXPLORATION COMPANY

CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY
(in thousands)

	Common Stock Shares	Common Stock Amounts	Additional Paid-in Capital	Unearned Stock Compensation	Accumulated Deficit	Predecessor Capital	Total
Balance, December 31, 1995	-	$ -	$ -	$ -	$ -	$ 3,694	$ 3,694
Net loss	-	-	-	-	-	(450)	(450)
Balance, December 31, 1996	-	-	-	-	-	3,244	3,244
Consummation of the Exchange	8,928,574	90	19,580	-	-	(3,244)	16,426
Issuance of stock options	-	-	2,576	(2,576)	-	-	-
Forfeiture of stock options	-	-	(69)	69	-	-	-
Issuance of common stock	3,325,000	33	23,894	-	-	-	23,927
Net loss for period ended February 27, 1997	-	-	(4,869)	-	-	-	(4,869)
Net income for period from February 27, 1997 to Dec. 31, 1997	-	-	3,807	-	(55)	-	3,752
Amortization of unearned stock compensation	-	-	-	833	-	-	833
Balance, December 31, 1997	12,253,574	123	44,919	(1,674)	(55)	-	43,313
Net loss	-	-	-	-	(33,345)	-	(33,345)
Issuance of common stock	1,052,632	10	9,419	-	-	-	9,429
Issuance of warrants	-	-	4,500	-	-	-	4,500
Amortization of unearned stock compensation	-	-	-	784	-	-	784
Balance, December 31, 1998	13,306,206	$ 133	$ 58,838	$ (890)	$ (33,400)	$ -	$ 24,681

See accompanying notes to the consolidated financial statements.

BRIGHAM EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year ended December 31, 1998	1997	1996
Cash flows from operating activities:			
Net loss	$ (33,345)	$ (1,117)	$ (450)
Adjustments to reconcile net loss to cash provided by operating activities:			
Depletion of natural gas and oil properties	8,410	2,743	2,323
Depreciation and amortization	413	306	487
Capitalized ceiling impairment	24,847	-	-
Amortization of stock compensation	372	388	-
Amortization of deferred loan fees and debt issuance costs	726	-	-
Amortization of discount on senior subordinated notes	286	-	-
Changes in working capital and other items:			
Increase in accounts receivable	(3,029)	(2,213)	(1,440)
(Increase) decrease in prepaid expenses	(10)	(128)	25
Increase in accounts payable	7,991	8,955	1,619
Increase (decrease) in participant advances received	275	(648)	804
Increase in interest payable on senior subordinated notes	507	-	-
Increase in other current liabilities	355	50	60
Increase in deferred interest payable - related party	-	53	320
Increase (decrease) in deferred income tax liability	(1,186)	1,186	-
Other noncurrent assets	6	281	(224)
Other noncurrent liabilities	7,004	(50)	186
Net cash provided by operating activities	13,622	9,806	3,710
Cash flows from investing activities:			
Additions to natural gas and oil properties	(84,055)	(57,170)	(13,612)
Proceeds from the sale of natural gas and oil properties	-	74	2,149
Additions to other property and equipment	(868)	(545)	(41)
(Increase) decrease in drilling advances paid	(152)	341	(292)
Net cash used by investing activities	(85,075)	(57,300)	(11,796)
Cash flows from financing activities:			
Proceeds from issuance of common stock	9,429	23,927	-
Proceeds from issuance of senior subordinated notes payable and warrants	40,000	-	-
Increase in notes payable	105,800	37,250	8,000
Repayment of notes payable	(78,800)	(13,250)	-
Principal payments on capital lease obligations	(236)	(179)	(269)
Deferred loan fees and debt issuance costs	(3,872)	-	-
Net cash provided by financing activities	72,321	47,748	7,731
Net increase (decrease) in cash and cash equivalents	868	254	(355)
Cash and cash equivalents, beginning of year	1,701	1,447	1,802
Cash and cash equivalents, end of year	$ 2,569	$ 1,701	$ 1,447
Supplemental disclosure of cash flow information:			
Cash paid during the year for interest	$ 5,490	$ 1,679	$ 762
Supplemental disclosure of noncash investing and financing activities:			
Capital lease asset additions	$ 320	$ 403	$ 101

See accompanying notes to the 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 "the Company." 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 natural gas and oil properties using 3-D seismic imaging and other advanced technologies. Since its inception, the Partnership has focused its exploration and development of natural gas and oil properties primarily in West Texas, the Anadarko Basin and the onshore Gulf Coast.

Pursuant to an exchange agreement dated February 26, 1997 (the "Exchange Agreement") and upon the initial filing on February 27, 1997 of a registration statement with the Securities and Exchange Commission (the "SEC") for the public offering of common stock (the "Offering"), the shareholders of Brigham, Inc. transferred all of the outstanding stock of Brigham, Inc. to the Company in exchange for 3,859,821 shares of common stock of the Company. Pursuant to the Exchange Agreement, the Partnership's other general partner and the limited partners also transferred all of their partnership interests to the Company in exchange for 3,314,286 shares of common stock of the Company. Furthermore, the holders of the Partnership's subordinated convertible notes transferred these notes to the Company in exchange for 1,754,464 shares of common stock. These transactions are referred to as "the Exchange." In completing the Exchange, the Company issued 8,928,571 shares of common stock to the stockholders of Brigham, Inc., the partners of the Partnership and the holder of the Partnership's subordinated notes payable. As a result of the Exchange, the Company now owns all the partnership interests in the Partnership. In May 1997, the Company sold 3,325,000 shares of its common stock in the Offering at a price of $8.00 per share.

2. Summary of Significant Accounting Policies

Basis of Accounting

The preparation of financial statements in conformity with generally accepted accounting principles 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. Actual results may differ from those estimates.

The Exchange has been reflected in the consolidated financial statements of the Company as a reorganization.

Principles of Consolidation

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

Cash and Cash Equivalents

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

Property and Equipment

The Company uses the full cost method of accounting for its investment in natural gas and oil properties. Under this method, all acquisition, exploration and development costs, including certain payroll and other internal costs, incurred for the purpose of finding natural gas and oil 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.

The capitalized costs of the Company's natural gas and oil properties plus future development, dismantlement, restoration and abandonment costs (the "Amortizable Base"), net of estimated of salvage values, are amortized using the unit-of-production method based upon estimates of total proved reserve quantities. The Company's capitalized costs of its natural gas and oil properties, net of accumulated amortization, are limited to the total of estimated future net cash flows from proved natural gas and oil 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 natural gas and oil. A reduction in the valuation of natural gas and oil properties resulting from declining prices or production could adversely impact depletion rates and capitalized cost limitations.

All costs directly associated with the acquisition and evaluation of unproved properties are initially excluded from the Amortizable Base. Upon the interpretation by the Company of the 3-D seismic data associated with unproved properties, the geological and geophysical costs related to acreage that is not specifically identified as prospective are added to the Amortizable Base. Geological and geophysical costs associated with prospective acreage, as well as leasehold costs, are added to the Amortizable Base when the prospects are drilled. Costs of prospective acreage are reviewed annually for impairment on a property-by-property basis.

At December 31, 1998, a capitalized ceiling impairment of $24.8 million was recognized. The write down was calculated based on the estimated discounted present value of future net cash flows from proved natural gas and oil reserves using prices in effect at December 31, 1998.

Other property and equipment, which primarily consists of 3-D seismic interpretation workstations, are 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

The Company recognizes natural gas and oil sales from its interests in producing wells under the sales method of accounting. Under the sales method, the Company recognizes revenues based on the amount of natural gas or oil sold to purchasers, which may differ from the amounts to which the Company is entitled based on its interest in the properties. Gas balancing obligations as of December 31, 1996, 1997 and 1998 were not significant.

Industry participants in the Company's seismic programs are charged on an hourly basis for the work performed by the Company on its 3-D seismic interpretation workstations. The Company recognizes workstation revenue as service is provided.

Derivative Instruments

Net realized gains or losses and related cash flows arising from the Company's commodity price swaps (see Note 11) are recognized in the period incurred as a component of natural gas and oil sales. If subsequent to being hedged, underlying transactions are determined not to be likely to occur, the related derivatives gains and losses are recognized in that period as "Other income."

Stock Based Compensation

The Company measures compensation expense for its stock based incentive plan using the intrinsic value method and has provided in Note 12 the pro forma disclosure of the effect on net loss and net loss per common share as if the fair value based method prescribed by Statement of Financial Accounting Standards ("SFAS") No. 123, "Accounting for Stock Based Compensation," had been applied in measuring compensation expense.

Federal and State Income Taxes

Prior to the consummation of the Exchange, there was no income tax provision included in the financial statements as the Partnership was not a taxpaying entity. Income and losses were passed through to its partners on the basis of the allocation provisions established by the partnership agreement. Upon consummation of the Exchange, the Partnership became subject to federal income taxes through its ownership by the Company.

In conjunction with the Exchange, the Company recorded a deferred income tax liability of $5 million to recognize the temporary differences between the financial statement and tax bases of the assets and liabilities of the Partnership at the Exchange date, February 27, 1997, given the provisions of enacted tax laws. Subsequent to this date, the Company elected to record a step-up in basis of its assets for tax purposes as a result of the Exchange. Related to this election, the Company recorded a $3.8 million deferred income tax benefit, resulting in a net $1.2 million deferred income tax charge for the year ended December 31, 1997.

Unaudited Pro Forma Information

Pro forma net loss for the year ended December 31, 1996 reflects the Exchange, including income taxes that would have been recorded had the Partnership been a taxable entity. Pro forma exchange adjustments primarily represent the amortization of the compensation expense related to employee stock options granted upon the formation of the Company (see Note 12), and the reduction of interest expense related to the elimination of debt as part of the Exchange. Pro forma income taxes have been included in the Statement of Operations pursuant to the rules and regulations of the SEC for instances when a partnership becomes subject to federal income taxes.

Comprehensive Income

In June 1997, the FASB issued SFAS No. 130, "Reporting Comprehensive Income." The standard, which was effective for financial statements issued for periods ending after December 15, 1997, established standards for reporting, in addition to net income, comprehensive income and its components including, as applicable, foreign currency items, minimum pension liability adjustments and unrealized gains and losses on certain investments in debt and equity securities. Adoption of this Standard has no impact on the Company's financial statements.

Recent Pronouncements

In June 1998, the FASB issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 requires that all derivative instruments be recorded on the balance sheet at fair value. 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. For fair value hedge transactions in which the Company is hedging changes in an asset's, liability's, or firm commitment's fair value, changes in the fair value of the derivative instrument will generally be offset in the income statement by changes in the hedged item's fair value. For cash flow hedge transactions in which the Company is hedging the variability of cash flows related to a variable-rate asset, liability, or a forecasted transaction, changes in the fair value of the derivative instrument will be reported in other comprehensive income. The gains and losses on the derivative instrument that are reported in other comprehensive income will be reclassified as earnings in the periods in which earnings are impacted by the variability of the cash flows of the hedged item. The ineffective portion of all hedges will be recognized in current period earnings. The Company must adopt SFAS No. 133 effective January 1, 2000. The Company is in the process of analyzing the potential impact of this standard on its financial statements presentation.

3. Acquisition

On November 12, 1997, the Company acquired a 50% interest in certain producing properties in Grady County, Oklahoma (the "Acquisition"). These properties were formerly owned by Mobil and were acquired by Ward Petroleum. The acquisition was accounted for as a purchase and the results of operations of the properties acquired were included in the Company's results of operations effective September 1, 1997. The purchase price of $13.4 million was financed primarily through the Company's existing revolving credit facility and was based on the Company's determination of the fair value of the assets acquired.

Pro Forma Information

The following unaudited pro forma statement of operations information has been prepared to give effect to the Acquisition as if the transaction had occurred at the beginning of 1996 and 1997. The historical results of operations have been adjusted to reflect (i) the difference between the acquired properties' historical depletion and such expense calculated based on the value allocated to the acquired assets, (ii) the increase in interest expense associated with the debt issued in the transaction, and (iii) the increase in federal income taxes related to historical net income attributable to the properties acquired. The pro forma amounts do not purport to be indicative of the results of operations that would have been reported had the Acquisition occurred as of the dates indicated, or that may be reported in the future (in thousands).

	Pro Forma Year Ended December 31,	
	1997	1996
Revenues	$ 11,194	$ 8,516
Costs and expenses:		
Lease operating and production taxes	1,864	1,300
General and administrative	3,570	2,199
Depletion of natural gas and oil properties	3,307	2,791
Depreciation and amortization	593	487
Interest expense, net	2,235	2,355
Total costs and expenses	11,569	9,132
Net loss before income taxes	(375)	(616)
Income tax expense	1,035	—
Net loss	$ (1,410)	$ (616)
Net loss per share:		
Basic/Diluted	$ (0.13)	$ (0.07)
Common shares outstanding:		
Basic/Diluted	11,081	8,929

4. Property and Equipment

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

	December 31,	
	1998	1997
Natural gas and oil properties	$ 179,867	$ 96,587
Accumulated depletion	(45,550)	(12,293)
	134,317	84,294
Other property and equipment:		
3-D seismic interpretation workstations and software	2,186	1,693
Office furniture and equipment	1,774	1,095
Accumulated depreciation	(1,946)	(1,549)
	2,014	1,239
	$ 136,331	$ 85,533

The accumulated depletion balance for natural gas and oil properties at December 31, 1998, includes the effect of a capitalized ceiling impairment of $24.8 million described at Note 2, "Property and Equipment."

The Company sold its interest in certain producing properties for $74,000 during 1997. No gain or loss was recognized on this transaction because the Company applies the full cost method of accounting for its investment in natural gas and oil properties.

The Company capitalizes certain payroll and other internal costs directly attributable to acquisition, exploration and development activities as part of its investment in natural gas and oil properties over the periods benefited by these activities. Capitalized costs do not include any costs related to production, general corporate overhead, or similar activities. During the years ended December 31, 1996, 1997 and 1998, these capitalized costs amounted to $1.8 million, $3.5 million and $4.6 million, respectively.

5. Notes Payable and Senior Subordinated Notes Payable

In April 1996, the Company entered into a revolving credit facility which provided for borrowings up to $25 million. On November 10, 1997, this facility was amended and the amount available under the agreement was increased to $75 million. The Company's borrowings under this facility were limited to a borrowing base determined periodically by the lender. This determination was based upon the proved reserves of the Company's natural gas and oil properties.

The amounts outstanding under this facility, excluding a $5.4 million special advance made November 12, 1997, bore interest, at the borrower's option, at the Base Rate or (i) LIBOR plus 1.75% if the principal outstanding was less than or equal to 50% of the borrowing base, (ii) LIBOR plus 2.0% if the principal outstanding was less than or equal to 75% but more than 50% of the borrowing base, and (iii) LIBOR plus 2.25% if the principal outstanding was greater than 75% of the borrowing base. The Base Rate is the fluctuating rate of interest per annum established from time to time by the lender. Interest accrued on the $5.4 million special advance at 11.50% per annum. The Company also paid a quarterly commitment fee of 0.5% per annum for the unused portion of the borrowing base.

In January 1998, the Company entered into a new reserve-based revolving credit facility (the "Credit Facility"). The Credit Facility originally provided for borrowings up to $75 million, all of which was immediately available for borrowing to fund capital expenditures. A portion of the funds available under the Credit Facility were used to repay in full the debt outstanding under the Company's previous revolving credit facility. Principal outstanding under the Credit Facility is due at maturity on January 26, 2001 with interest due monthly for base rate tranches or periodically as LIBOR tranches mature. Amounts outstanding under the Credit Facility bore interest at either the lender's Base Rate or LIBOR plus 2.25%, at the Company's option. The Credit Facility contains covenants restricting the Company's ability to declare or pay dividends on its stock. In connection with the origination of the Credit Facility, certain bank fees and other expenses totaling approximately $1.9 million were recorded as deferred costs and are amortized over the life of the loan. The Credit Facility's borrowing base was reduced to $65 million upon issuance of the senior subordinated notes in August 1998.

In March 1999, the Company and its lenders entered into an amendment to the Credit Facility. Pursuant to this amendment, the borrowing availability under the Credit Facility remains at $65 million and the initial borrowing availability redetermination date was extended from January 31, 1999 to June 1, 1999, when the borrowing availability will be redetermined by the lenders based on the Company's then proved reserve value and cash flows. To the extent that the amounts outstanding under the Credit Facility exceed the borrowing availability at the redetermination date, the Company may be required to repay such excess under provision of the amendment. In addition, certain financial covenants have been amended, additional covenants have been included that place significant restrictions on the Company's ability to make certain capital expenditures, and the annual interest rate for borrowings under the Credit Facility is revised to the lender's base rate or LIBOR plus 3.0% and the Company will pay the lender a $500,000 transaction fee over a ten month period. The Company's obligations under the Credit Facility are secured by substantially all of the natural gas and oil properties and other tangible assets of the Company.

In August 1998, upon the filing of a registration statement with the SEC, the Company issued $50 million of debt and equity securities to two affiliated institutional investors. The financing transaction consisted of the issuance of $40 million of senior subordinated secured notes (the "Notes") with warrants (the "Warrants") to purchase the Company's common stock and the sale of $10 million of the Company's common stock, or 1,052,632 shares at a price of $9.50 per share. The combined sale of the Notes and common stock of the Company generated proceeds, net of offering costs, of approximately $47.5 million that was used to repay a portion of the then outstanding borrowings under the Company's Credit Facility.

The Notes mature in August 2003, with no principal payments required until maturity and quarterly interest payments payable either in cash at an annual rate of 12% or, in limited circumstances, the issuance of additional notes at an annual interest rate of 13% for the first three years. The Company may repay the Notes in full without premium at any time prior to maturity. The indenture governing the Notes contains certain covenants including, but not limited to, limitations or restrictions on indebtedness, distributions, affiliate transactions, liens and sale and leaseback transactions. The indenture prohibits all dividends on the Company's stock. Warrants to purchase 1 million shares of the Company's common stock exercisable during a period of seven years at a price of $10.45 per share were issued in connection with the Notes.

The Notes are fully and unconditionally guaranteed, on a joint and several basis, by each of the Company's subsidiaries (the "Subsidiary Guarantors"), all of which are directly or indirectly wholly-owned by the Company. The obligations of the Subsidiary Guarantors under the subsidiary guaranty agreements are subordinated to the senior indebtedness of the Subsidiary Guarantors. The assets of the parent, Brigham Exploration Company, consist solely of investments in its subsidiaries.

Concurrent with the issuance of the Notes, the Company recorded a discount on the Notes of $4.5 million to reflect the estimated value of the Warrants. Also in connection with the issuance of the Notes, certain fees and expenses totaling approximately $1.8 million were recorded as deferred costs. The Note discount and deferred fees are amortized over the five year term of the Notes.

In March 1999, the indenture governing the Notes was amended to provide the Company with the option to pay interest due on the Notes in kind, for any reason, through the second quarter of 2000. In addition, certain financial and other covenants were amended. The amendment also provides for a reduction in the exercise price per share of the Warrants from $10.45 per share to $3.50 per share.

6. Capital Lease Obligations

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

	December 31, 1998	December 31, 1997
3-D seismic interpretation workstations and software	$ 620	$ 497
Office furniture and equipment	167	204
	787	701
Accumulated depreciation and amortization	(276)	(241)
	$ 511	$ 460

The obligations under capital leases are at fixed interest rates ranging from 8.7% to 17.9% and are collateralized by property, plant and equipment. The future minimum lease payments under the capital leases and the present value of the net minimum lease payments at December 31, 1998 are as follows (in thousands):

1999	$ 323
2000	237
2001	95
2002	24
Total minimum lease payments	679
Estimated executory costs included in capital leases	(50)
Net minimum lease payments	629
Amounts representing interest	(90)
Present value of net minimum lease payments	539
Less: current portion	(240)
Noncurrent portion	$ 299

7. Income Taxes

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

	Year ended December 31, 1998	Year ended December 31, 1997
Current income taxes:		
Federal	$ —	$ —
State	—	—
Deferred income taxes:		
Federal	(1,186)	1,186
State	—	—
	$ (1,186)	$ 1,186

The difference 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, 1998	Year ended December 31, 1997
Tax at statutory rate	$ (11,740)	$ 23
Add (deduct) the effect of:		
January and February 1997 income, not taxable	—	(44)
Tax effect of Exchange	—	1,193
Nondeductible expenses	10	14
Valuation reserve	10,544	—
	$ (1,186)	$ 1,186

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

	December 31, 1998	December 31, 1997
Deferred tax assets:		
Net operating loss carryforwards	$ 11,219	$ 5,563
Amortization of stock compensation	258	132
Other	3	3
	11,480	5,698
Deferred tax liability:		
Depreciable and depletable property	(936)	(6,884)
Valuation reserve	(10,544)	—
	$ —	$ (1,186)

At December 31, 1998, the Company had regular and alternative minimum tax net operating loss carryforwards of approximately $32.9 million and $23.7 million, respectively, each including separate return limitation year carryovers of approximately $1.2 million, which expire by December 31, 2018.

8. Net Income (Loss) Per Share

Net income (loss) per share is presented in the consolidated financial statements based on a basic EPS calculation as well as a diluted EPS calculation. Basic EPS is computed by dividing net income (loss) applicable to common shareholders by the weighted average number of common shares outstanding during each period. Diluted EPS is computed by dividing net income (loss) applicable to common shareholders by the weighted average number of common shares and common share equivalents outstanding (if dilutive), during each period. The number of common share equivalents outstanding is computed using the treasury stock method.

Historical net loss per common share for 1996 is based on shares issued upon consummation of the Exchange, assuming such shares has been outstanding for all periods presented. Net loss per share for 1997 is presented giving effect to the shares issued pursuant to the Exchange as well as shares issued in the initial public offering. At December 31, 1997 and 1998, options and warrants to purchase 628,737 and 1,194,654, respectively, shares of common stock were outstanding but were not included in the computation of diluted EPS due to the anti-dilutive effect they would have on EPS if converted.

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

Litigation

The Company 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 the Company.

As of December 31, 1998, there were no known environmental or other regulatory matters related to the Company's operations which are reasonably expected to result in a material liability to the Company. Compliance with environmental laws and regulations has not had, and is not expected to have, a material adverse effect on the Company's capital expenditures, earnings or competitive position.

Lease Commitments

The Company leases office equipment and space under operating leases expiring at various dates through 2002. The future minimum annual rental payments under the noncancelable terms of these leases at December 31, 1998, are as follows (in thousands):

1999	$ 868
2000	790
2001	789
2002	395
	$ 2,842

Rental expense for the years ended December 31, 1996, 1997 and 1998 was $253,112, $606,173 and $875,150, respectively.

Factors Which May Affect Future Operations

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

Due to an expectation for continuing difficult industry and capital markets conditions, the Company has substantially reduced its planned capital budget for 1999 and has undertaken a number of strategic initiatives in an effort to improve and preserve its capital liquidity in the current environment. The Company has adapted its business strategy in the near-term through the implementation of the following principal strategic initiatives: (i) focusing all of the Company's planned exploration efforts in 1999 towards the drilling of its highest grade 3-D prospects, (ii) eliminating substantially all planned seismic and land expenditures for new projects until its capital resources can support such additional activity, (iii) seeking to divest certain producing natural gas and oil properties in an effort to raise capital to reduce debt borrowings and to redirect capital to drilling projects that have the potential to generate higher investment returns, (iv) restructuring its outstanding senior and subordinated debt agreements to provide the Company with flexibility needed to preserve cash flow to fund its expected near-term exploration activities, (v) implementing an overhead reduction plan to reduce annual general and administrative expenses, and (vi) evaluating opportunities to raise additional equity capital either through the sales of interests in certain of its seismic projects or the issuance of equity securities. The Company believes that the successful execution of these strategic initiatives will provide it with sufficient capital resources to execute its planned 1999 exploration program and position it to realize the significant value it believes it has captured in its inventory of 3-D seismic projects and delineated drilling locations. While the Company has initiated each of these strategic directives in late 1998 and early 1999, and has effected certain of them to date, the successful completion of any or all of these efforts to improve the Company's capital availability within the expected time frame is uncertain and will likely have a material impact on the Company's near-term capital expenditure levels and growth profile.

10. Segment Information

In June 1997, the FASB issued SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information," which the Company adopted in the first quarter of 1998. The statement supersedes SFAS No. 14, "Financial Reporting for Segments of a Business Enterprise," replacing the "industry segment" approach with the "management" approach. The management approach designates the internal organization that is used by management for making operating decisions and assessing performance as the source of the Company's reportable segments. It also requires disclosures about products and services, geographic areas and major customers.

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

During 1998, approximately 25%, 15%, 11% and 11% of the Company's natural gas and oil production was sold to four separate customers. During 1997, approximately 14% and 12% of the Company's natural gas and oil production was sold to two separate customers. During 1996, approximately 16%, 12% and 10% of the Company's natural gas and oil production was sold to three separate customers. However, due to the availability of other markets, the Company does not believe that the loss of any one of these individual customers would adversely affect the Company's result of operations.

11. Financial Instruments

The Company periodically enters into commodity price swap agreements 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 the underlying volumes. The notional amounts of these derivative financial instruments are based on planned production from existing wells. The Company uses these derivative financial instruments to manage market risks resulting from fluctuations in commodity prices. Commodity price swaps are effective in minimizing these risks by creating essentially equal and offsetting market exposures. The derivative financial instruments held by the Company are not leveraged and are held for purposes other than trading.

In 1996 and 1997, the Company was a party to a crude oil swap arrangement resulting in a fixed price over a period of time for a specified volume of crude oil. Adjustment to the price received for oil under these swap arrangements resulted in a decrease in oil revenues of $301,280 and $6,191 in 1996 and 1997, respectively.

In February 1998, the Company entered into a hedging contract whereby 10,000 MMBtu per day of natural gas is purchased and sold subject to a fixed price swap agreement for monthly periods from April 1998 through October 1999. Pursuant to these arrangements the Company exchanges a floating market price for a contract month and payments are received when the fixed price exceeds the floating price. Total natural gas subject to this hedging contract is 2,750,000 MMBtu in 1998 and 3,040,000 MMBtu in 1999. As a result of this natural gas hedging contract, the Company realized an increase in revenues of $555,240 during 1998.

In August 1998, the Company entered into a hedging contract whereby 5,000 MMBtu per day of natural gas is purchased and sold subject to a fixed price swap agreement for monthly periods from April 1999 through October 1999. Pursuant to these arrangements the Company exchanges a floating market price for a fixed contract price of $2.015 per MMBtu. Payments are made by the Company when the floating price exceeds the fixed price for a contract month and payments are received when the fixed price exceeds the floating price. Total natural gas subject to this hedging contract is 1,070,000 MMBtu in 1999.

In January 1999, the Company entered into a swap agreement with terms similar to existing agreements which relates to production for monthly periods from November 1999 through April 2001. Pursuant to these arrangements, 15,000 MMBtu per day of natural gas is purchased and sold subject to a fixed price swap agreement, and the Company exchanges a floating market price for a fixed contract price of $2.065 per MMBtu. Total natural gas volumes subject to this agreement are 915,000 MMBtu, 5,490,000 MMBtu and 1,800,000 MMBtu in 1999, 2000 and 2001, respectively.

The Company'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 maturities. The carrying value of the Company's revolving credit facility (see Note 5) approximates its fair market value since it bears interest at floating market interest rates.

The Company's accounts receivable relate to natural gas and oil sales to various industry companies, amounts due from industry participants for expenditures made by the Company on their behalf and workstation revenues. Credit terms, typical of industry standards, are of a short-term nature and the Company does not require collateral. The Company's accounts receivable at December 31, 1998 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.

12. Employee Benefit Plans

Retirement Savings Plan

During 1996 the Company adopted a defined contribution 401(k) plan for substantially all of its employees. Eligible employees may contribute up to 15% of their compensation to this plan. The 401(k) plan provides that the Company may, at its discretion, match employee contributions. The Company has not matched employee contributions in any plan year.

Stock Compensation

In 1994 three employees were granted restricted interests in the Company which vest in increments through July 1999. At the date of grant, the value of these interests was immaterial. On February 26, 1997, in connection with the Exchange (see Note 1), the three employees transferred these company interests to the Company in exchange for 156,250 shares of restricted common stock of the Company. The terms of the restricted stock and the restricted company interests are substantially the same. The shares vest over a three-year period ending in 1999. No compensation expense will result from this exchange.

The Company adopted an incentive plan, effective upon completion of the Exchange (see Note 1), which provides for the issuance of stock options, stock appreciation rights, stock, restricted stock, cash or any combination of the foregoing. The objective of this plan is to reward key employees whose performance may have a significant effect on the success of the Company. An aggregate of 1,588,170 shares of the Company's common stock was reserved for issuance pursuant to this plan. The Compensation Committee of the Board of Directors will determine the type of awards made to each participant and the terms, conditions and limitations applicable to each award. Options granted subsequent to March 4, 1997 have an exercise price equal to the fair market value of the Company's common stock on the date of grant and generally vest, in increments, over five to six years.

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

The following table summarizes activity under the incentive plan for each of the two years ended December 31, 1998:

	Shares	Weighted Average Exercise Price
Options outstanding December 31, 1996	—	$ —
Options granted	646,097	5.03
Options forfeited or cancelled	(17,360)	5.00
Options exercised	—	—
Options outstanding December 31, 1997	628,737	5.03
Options granted	873,500	8.62
Options forfeited or cancelled	(307,583)	(12.88)
Options exercised	—	—
Options outstanding December 31, 1998	1,194,654	$ 5.63

On December 14, 1998, the Board of Directors approved a proposal to cancel and reissue outstanding employee stock options which were granted in January 1998 with an exercise price of $12.88. A total of 305,250 options with an exercise price of $12.88 per share were cancelled and reissued with an exercise price of $6.31 per share, the fair market value of the Company's stock at the date of reissuance. Vesting schedules remained unchanged by the reissuance.

Exercise prices for options outstanding at December 31, 1997 range from $5.00 to $14.375 and remaining contractual lives range from 5.5 years to 6 years. Exercise prices for options outstanding at December 31, 1998 range from $5.00 to $14.375 and remaining contractual lives range from 5.5 years to 7 years. No options were exercisable at December 31, 1997 and 145,740 were exercisable at December 31, 1998.

The weighted average fair value per share of stock compensation issued during 1997 and 1998 was $6.24 and $5.40, respectively. The fair value for these options was estimated using the Black-Scholes model with the following weighted average assumptions for grants made in 1997 and 1998: risk free interest rate of 6.24% and 4.70%; volatility of the expected market prices of the Company's common stock of 38% and 77%; expected dividend yield of zero and weighted average expected option lives of 7.3 and 5.0 years, respectively.

The Black-Scholes valuation model was developed for use in estimating the fair value of traded options which have no vesting restrictions and are transferable. Additionally, the assumptions required by the valuation model are highly subjective. Because the Company'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 the Company's stock options.

Had compensation cost for the Company'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 No. 123 the Company's net loss and net loss per share for 1998, 1997 and 1996 would have been the pro forma amounts indicated below:

	1998	1997
Net loss:		
As reported	$ (33,345)	$ (1,117)
Pro forma	(33,591)	(1,314)
Net loss per share:		
As reported	(2.64)	(0.10)
Pro forma	(2.66)	(0.12)

The Company granted 644,097 stock options as of March 4, 1997. These options have an exercise price of $5.00 compared to an originally determined estimated fair market value of the Company's common stock at date of grant of $8.00. This grant resulted in noncash compensation expense which is being recognized over the related vesting period of the options. During 1999, the Company revised the fair market value of its common stock at the date these options were granted from $8.00 to $9.00. As a result, the Company restated its financial statements to reflect the impact of this change in estimate.

The impact of the restatement on the 1997 financial statements is presented below:

	As Previously Reported	As Restated
For the year ended December 31, 1997		
Net loss	$ (1,036)	$ (1,117)
Net loss per share:		
Basic/Diluted	(0.09)	(0.10)
As of December 31, 1997		
Retained earnings/(accumulated deficit)	26	(55)
Total stockholders' equity	43,153	43,313

13. Related Party Transactions

During the years ended December 31, 1996, 1997 and 1998, the Company paid approximately $596,000, $837,000 and $851,000 respectively, in fees for land acquisition services performed by a company owned by a brother of the Company's President and Chief Executive Officer. Other participants in the Company's 3-D seismic projects reimbursed the Company for a portion of these amounts.

In 1996 and 1997, the Company paid $110,000 and $18,000 for working interests in natural gas and oil properties owned by affiliates of a member of the Company's board of directors/management committee. The Company billed the affiliates $68,000 in 1996 for their proportionate share of the costs related to this project.

A Director of the Company served as a consultant to the Company on various aspects of the Company's business and strategic issues. Fees paid for these services by the Company were $79,200, $86,580 and $100,539 for the twelve month periods ended December 31, 1996, 1997 and 1998, respectively. Additional disbursements totaling approximately $13,000 and $12,000 were made during 1997 and 1998, respectively, for the reimbursement of certain expenses.

14. Subsequent Event

In February 1999, the Company 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, the Company conveyed 100% of its working interest in land and seismic in these project areas to a newly formed limited liability company (the "Duke LLC") for a total consideration of $10 million. The Company is the managing member of the Duke LLC with a 1% interest, and Duke is the sole remaining member with a 99% interest. Pursuant to the terms of the Duke LLC agreement, the Company pays 100% of the drilling and completion costs for all wells drilled by the 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, the Company has certain rights to back-in for up to a 94% effective working interest in the Duke LLC properties.

15. Natural Gas and Oil Exploration and Production Activities

The tables presented below provide supplemental information about natural gas and oil exploration and production activities as defined by SFAS No. 69, “Disclosures about Oil and Gas Producing Activities.”

Results of Operations for Natural Gas and Oil Producing Activities (in thousands)

	Year ended December 31,		
	1998	1997	1996
Natural gas and oil sales	$ 13,799	$ 9,184	$ 6,141
Costs and expenses:			
Lease operating	2,172	1,151	726
Production taxes	850	549	362
Depletion of natural gas and oil properties	8,410	2,743	2,323
Capitalized ceiling impairment	24,847	—	—
Income tax expense (benefit) (a)	(7,868)	1,318	—
Total costs and expenses	28,411	5,761	3,411
	$ (14,612)	$ 3,423	$ 2,730
Depletion per physical unit of production (equivalent Mcf of gas)	$ 1.27	$ 0.88	$ 1.13

(a) The income tax expense (benefit) for 1997 and 1998 is calculated at the statutory rate and determined without regard to the Company’s deduction for general and administrative expenses, interest costs and other income tax deductions and credits.

Natural gas and oil 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. No provision was made for income taxes for 1996 since these taxes are the responsibility of the partners (see Note 2). Depletion of natural gas and oil 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 natural gas and oil acquisition, exploration and development activities follow (in thousands):

	December 31,		
	1998	1997	1996
Costs incurred for the year:			
Exploration	$ 67,110	$ 29,516	$ 10,527
Property acquisition	16,245	26,956	6,195
Development	10,427	2,953	1,328
Proceeds from participants	(10,502)	(319)	(4,111)
	$ 83,280	$ 59,106	$ 13,939

Costs incurred represent amounts incurred by the Company for exploration, property acquisition and development activities. Periodically, the Company 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.

Capitalized costs related to natural gas and oil acquisition, exploration and development activities follow (in thousands):

	December 31, 1998	December 31, 1997
Cost of natural gas and oil properties at year-end:		
Proved	$ 127,491	$ 67,744
Unproved	52,376	28,843
Total capitalized costs	179,867	96,587
Accumulated depletion	(45,550)	(12,293)
	$ 134,317	$ 84,294

Following is a summary of costs (in thousands) excluded from depletion at December 31, 1998, by year incurred. At this time, the Company 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, 1998	1997	1996	Prior Years	Total
Property acquisition	$ 9,659	$ 13,161	$ 1,176	$ 1,278	$ 25,274
Exploration	21,577	5,072	320	133	27,102
Total	$ 31,236	$ 18,233	$ 1,496	$ 1,411	$ 52,376

16. Natural Gas and Oil Reserves and Related Financial Data (Unaudited)

Information with respect to the Company's natural gas and oil 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 the Company's independent petroleum consultants and internal petroleum reservoir engineer.

Natural Gas and Oil Reserve Data

The following tables present the Company's estimates of its proved natural gas and oil reserves. The Company emphasizes that reserve estimates are approximates and are expected to change as additional information becomes available. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact way, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Accordingly, there can be no assurance that the reserves set forth herein will ultimately be produced nor can there be assurance that the proved undeveloped reserves will be developed within the periods anticipated. A substantial portion of the reserve balances were estimated utilizing the volumetric method, as opposed to the production performance method.

	Natural Gas (MMcf)	Oil (MBbls)
Proved reserves at December 31, 1995	4,257	1,672
Revisions to previous estimates	(1,005)	(232)
Extensions, discoveries and other additions	7,742	996
Purchase of minerals-in-place	260	3
Sales of minerals-in-place	(299)	(272)
Production	(698)	(227)
Proved reserves at December 31, 1996	10,257	1,940
Revisions to previous estimates	(3,044)	(447)
Extensions, discoveries and other additions	33,721	735
Purchase of minerals-in-place	13,718	1,244
Sales of minerals-in-place	(40)	—
Production	(1,382)	(291)
Proved reserves at December 31, 1997	53,230	3,181
Revisions of previous estimates	(26,696)	(115)
Extensions, discoveries and other additions	48,050	1,752
Purchase of minerals-in-place	851	11
Production	(4,269)	(396)
Proved reserves at December 31, 1998	71,166	4,433
Proved developed reserves at December 31:		
1996	6,034	1,453
1997	30,677	2,665
1998	38,571	2,935

Proved reserves are estimated quantities of crude natural gas and 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 which 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 natural gas and oil reserves. Future cash flows were computed by applying year end prices of natural gas and oil relating to the Company'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 natural gas and oil 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 the Company's natural gas and oil reserves.

BRIGHAM EXPLORATION COMPANY

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	December 31,		
	1998	1997	1996
Future cash inflows	$ 198,082	$ 165,156	$ 84,987
Future development and production costs	(61,064)	(40,923)	(20,998)
Future income taxes	(6,972)	(22,919)	—
Future net cash inflows	$ 130,046	$ 101,314	$ 63,989
Future net cash inflow before income taxes, discounted at 10% per annum	$ 81,741	$ 69,249	$ 44,506
Standardized measure of future net cash inflows discounted at 10% per annum	$ 81,649	$ 64,274	$ 44,506

The base sales prices for the Company's reserves were $3.71 per Mcf for natural gas and $25.37 per Bbl for oil as of December 31, 1996, $2.27 per Mcf for natural gas and $15.50 per Bbl for oil as of December 31, 1997, and $2.12 per Mcf for natural gas and $9.50 per Bbl for oil as of December 31, 1998. 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 the Company's reserves at these dates.

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

	December 31,		
	1998	1997	1996
Beginning of period	$ 64,274	$ 44,506	$ 18,222
Sales of natural gas and oil produced, net of production costs	(10,776)	(7,484)	(5,053)
Development costs incurred	5,423	1,955	246
Extensions and discoveries	52,389	38,016	29,457
Purchases of minerals-in-place	687	16,965	384
Sales of minerals-in-place	—	(94)	(2,380)
Net change of prices and production costs	(11,921)	(20,466)	7,023
Change in future development costs	(656)	319	303
Changes in production rates and other	(6,109)	(1,954)	(342)
Revisions of quantity estimates	(23,470)	(6,964)	(5,176)
Accretion of discount	6,925	4,450	1,822
Change in income taxes	4,883	(4,975)	—
End of period	$ 81,649	$ 64,274	$ 44,506

Corporate Information

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

Gulf Coast Office
450 Gears Road
Suite 240
Houston, Texas 77067
Phone: 281.874.0707
Fax: 281.874.9666

Corporate Internet Address
Home Page: www.bexp3d.com
E-Mail: investor@bexp3d.com

Independent Auditors
PricewaterhouseCoopers LLP
Houston, Texas

Legal Counsel
Thompson & Knight, P.C.
Dallas, Texas

Independent Petroleum Engineers
Cawley, Gillespie & Associates, Inc.
Fort Worth, Texas

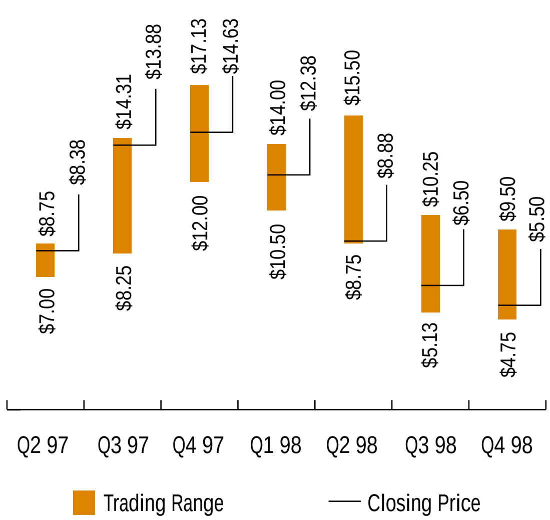
Stock Transfer Agent and Registrar
American Stock Transfer and Trust Company
40 Wall Street, 46th Floor
New York, New York 10005
Phone: 800.937.5449

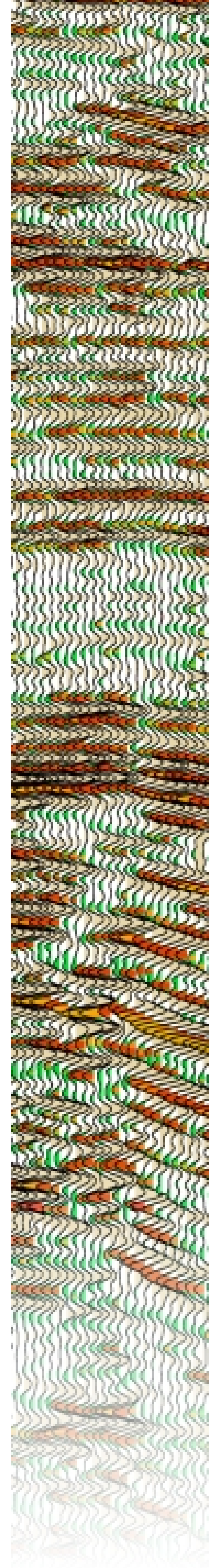
Annual Shareholders Meeting
Brigham Exploration Company will hold its annual meeting of shareholders at 1:00 pm Central on Thursday, May 13, 1999, at River Place Country Club in Austin, Texas.

Information Requests
Anyone wishing to obtain more information about Brigham Exploration Company, including copies of the Company'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 investor@bexp3d.com.

Common Stock Trading Data

Brigham Exploration Company completed its initial public offering of common stock on May 8, 1997. The Company's common stock trades on The Nasdaq Stock Market℠ under the symbol BEXP. At December 31, 1998, the Company had 13,306,206 shares of common stock outstanding. The high and low market trading prices for the Company's shares by quarter for the last two years are provided below.





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