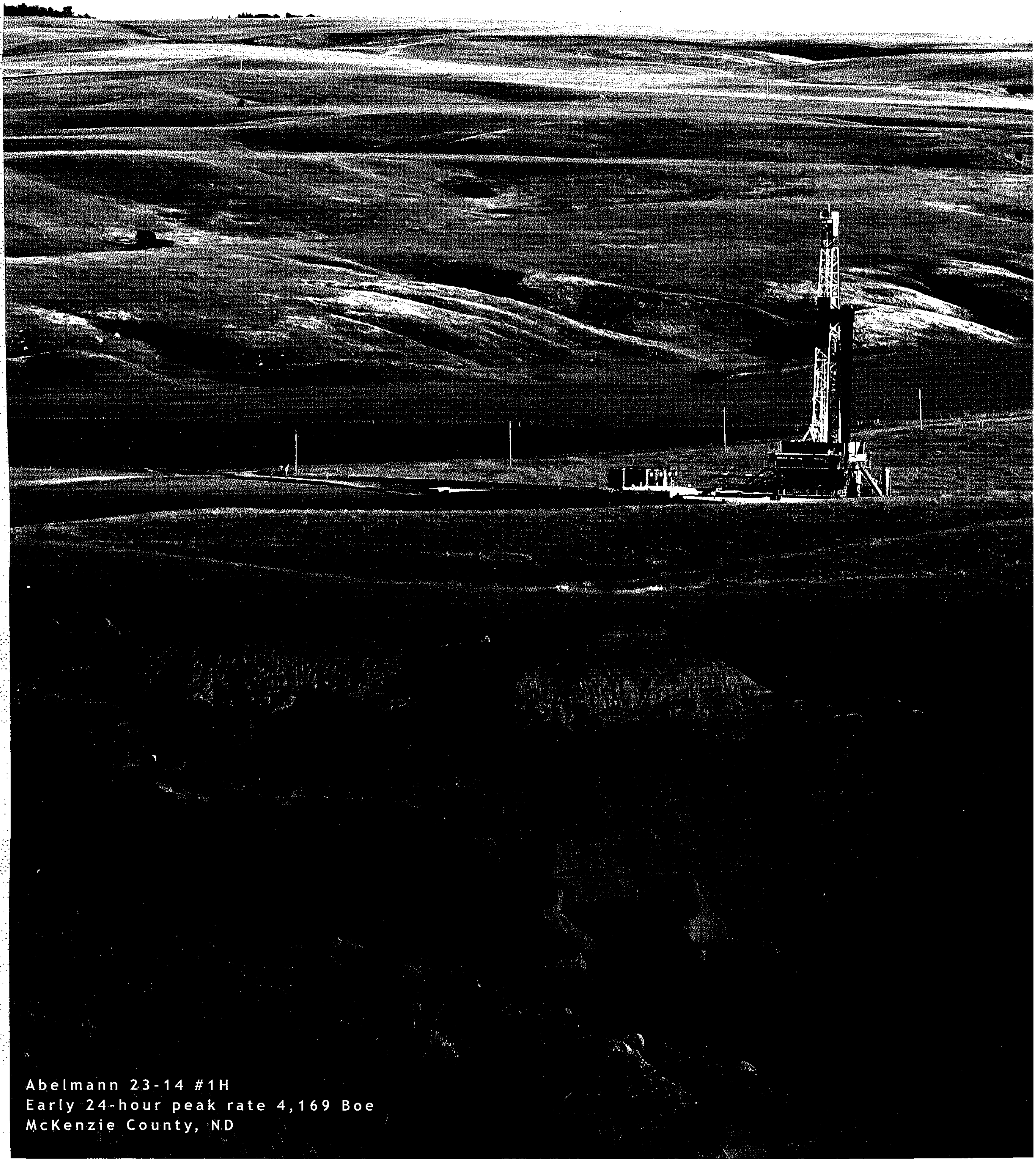
BRIGHAM

2010 ANNUAL REPORT / NO OIL LEFT BEHIND ™



Abelmann 23-14 #1H
Early 24-hour peak rate 4,169 Boe
McKenzie County, ND

BRIGHAM'S FORMULA FOR SUCCESS

....

INNOVATIVE & ENTREPRENEURIAL STAFF

87 OPERATIONS, EXPLORATION, LAND AND SUPPORT STAFF.

....

PREMIER ACREAGE POSITION

371,200 NET WILLISTON BASIN ACRES IN NORTH DAKOTA AND MONTANA.

....

DRILLING & COMPLETION FORMULA

GEOSTEERING. SWELL PACKERS. PERF & PLUG. CERAMIC PROPPANT.

....

DRIVES OUR SIGNIFICANT OIL PRODUCTION & RESERVE GROWTH

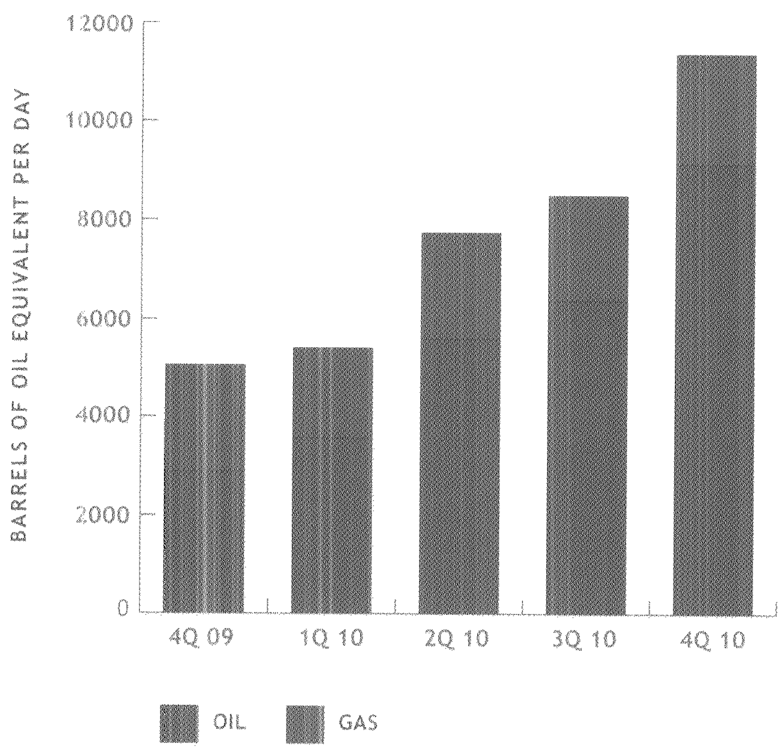
GEOSTEERING

We recognized that horizontal drilling controlled by geosteering would become one of the most valuable technologies to be introduced in the oil & gas business. In unconventional formations, such as the Bakken, precise geosteering within the target zone allows us to maximize the benefits of our multi-stage fracs.

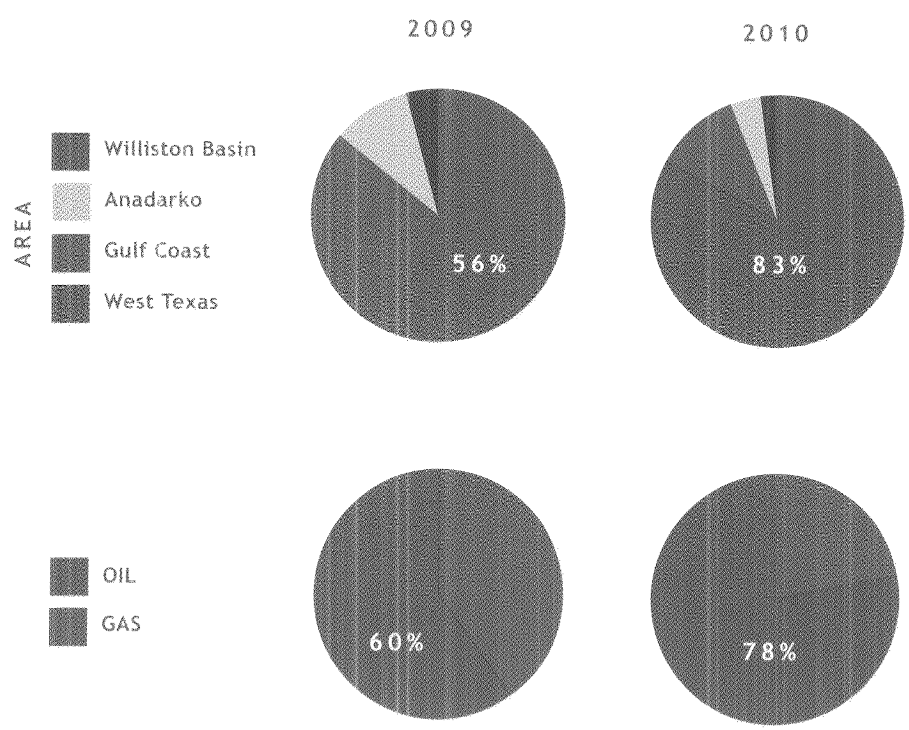
CERAMIC PROPPANT

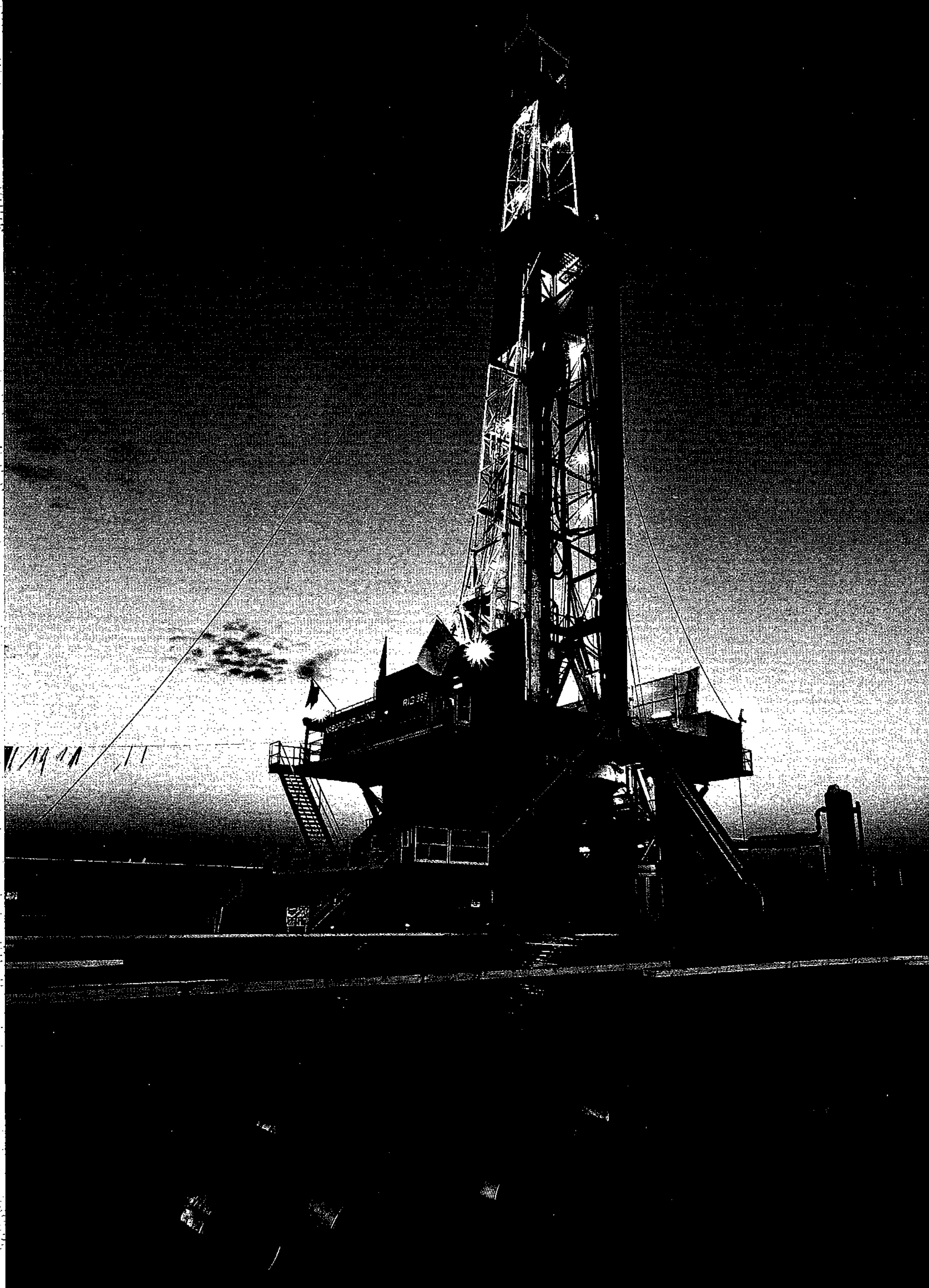
We have been using ceramic proppant for many years to create and maintain high perm channels through which hydrocarbons can flow, thereby increasing both production rates and the overall amount of oil or gas recovered. Based on research supported by the Society of Petroleum Engineers, the additional strength and uniform size and shape of ceramic proppant provides higher performance (SPE 77675).

OUR WILLISTON BASIN DRILLING RESULTS HAVE DRIVEN SIGNIFICANT OIL PRODUCTION GROWTH ...



... AND SIGNIFICANT RESERVE GROWTH FROM 27.7 MMBOE IN 2009 TO 66.8 MMBOE IN 2010.





SWELL PACKERS

Swell packers are used for effective zonal isolation in the well completion process. The simplicity, reliability and effectiveness of swell packers allows us to stimulate the entire length of the horizontal wellbore from toe to heel. We effectively create a "rubble zone" near the wellbore, which helps us to maximize oil recoveries.

PERF & PLUG

Initiation of fractures is controlled by selectively perforating four intervals between each swell packer. We believe fracture pathways are initiated at these perforations. Plugs are used to isolate the next section of the wellbore to be stimulated. Utilizing "perf and plug" helps us to achieve our goal of "NO OIL LEFT BEHIND™."

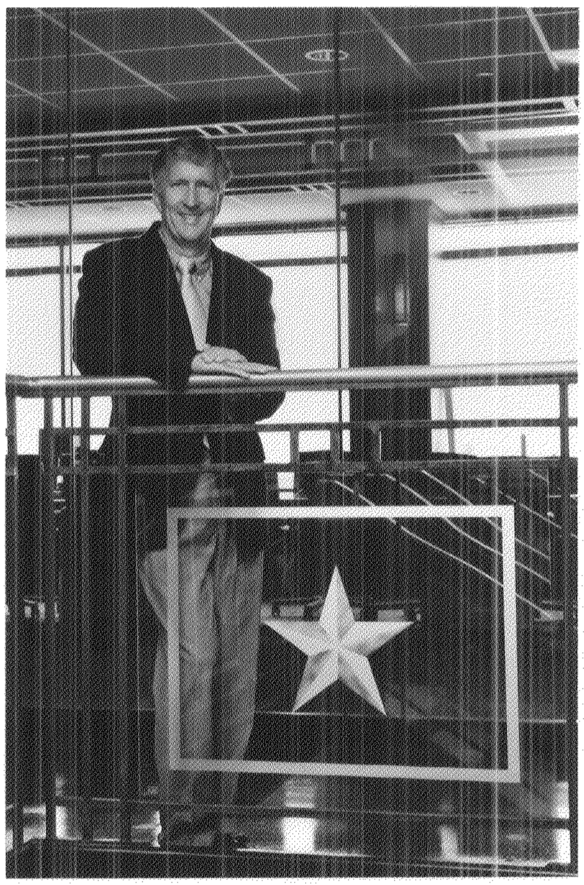
Williston Basin Timeline

2005
- Acquired initial leases in Rough Rider (Williams & McKenzie Counties, ND)
- 46,000 net acres at year-end

LETTER TO STOCKHOLDERS

BEN "BUD" M. BRIGHAM

IT IS MY PLEASURE TO REPORT TO OUR STOCKHOLDERS ON OUR SUBSTANTIAL ACCOMPLISHMENTS DURING 2010.



"NO OIL LEFT BEHIND™"

Our new slogan embraces the spirit of our efforts in leveraging the resourcefulness of our employees and the application of leading edge technologies to efficiently develop what we believe to be the premier core acreage position in the top resource play in North America. Today, our industry's Bakken and Three Forks Williston Basin production is surpassing, or very close to surpassing, that of North America's largest oil field, Prudhoe Bay. We believe the Bakken and Three Forks reservoirs will ultimately be recognized as the largest North American oil field discovery made in the last 40 years. From my perspective, the current activity in western North Dakota and Montana parallels the early development of the Permian Basin of West Texas, where I grew up. It's very exciting to see the positive impact the oil and gas industry is having on North Dakota and Montana, and we are very grateful for the opportunity to work with the people of North Dakota and Montana to provide energy in America for Americans.

2006 IN THE WB

- Drilled initial Bakken long lateral, single frac stage wells in Rough Rider
- Acquired initial leases in Eastern Montana
- 120,000 net acres at year-end
- 3.0 net wells drilled

It is a credit to our staff and our company's leadership that our early move into the Williston Basin in 2005 has provided us with a potential 12 to 20 year drilling inventory. Subsequent to that aggressive entry, persistence and determination, combined with entrepreneurial innovation and emerging technologies, enabled us to generate highly economic results that would have previously been described as unimaginable. Today as I write this letter, we've drilled 59 consecutive, yes that's consecutive, successful long lateral, high frac stage Bakken and Three Forks wells in North Dakota with an average early 24-hour peak rate of approximately 2,860 barrels of oil equivalent. Quite a remarkable outcome, but it is only the beginning. We believe we may have 1,300 to 2,200 potential drilling locations to develop in our core areas, providing us with fuel for many years of growth in production and cash flow. That is a very bright future for our stockholders.

Before we look ahead to our 2011 objectives, let us briefly look back at 2010. The following are our goals that I laid out in last year's stockholder letter and our progress in achieving those goals. I am very happy to report that we essentially accomplished all of our 2010 goals.

2010 GOALS & RESULTS >

ONE / ***Accelerate our Williston Basin Bakken and Three Forks operated drilling program, providing us with the potential to drill up to 469 remaining net development locations on our current core acreage position over a reduced time frame.***

Given the success we had delineating acreage, our de-risked drilling inventory grew from 469 net locations to 724-1,209 net locations, depending on whether you view the Three Forks as being de-risked in our Rough Rider area.

During 2010 we accelerated our operated drilling program from four rigs as we began the year to seven rigs by late December, and, as planned, we expect to add our eighth rig by May 2011.

We invested approximately $425 million in exploration and development capital during the year, exceeding our expectations in terms of both net wells drilled and new acreage added to inventory.

TWO / ***Drill our first Three Forks well on our 120,000 net acre Rough Rider project area, which could potentially begin to delineate an additional 281 net Three Forks drilling locations. Other operators have drilled discoveries to the southeast and west of our acreage, partially de-risking the Three Forks in the area, but we look forward to using our drilling and completion formula that has generated strong results in the area in the Bakken formation.***

Our first Rough Rider Three Forks well, the State 36-1 #2H, was completed at a 24-hour peak rate of approximately 2,356 barrels of oil equivalent and continues to perform strongly. Based on publicly released data, this is the highest initial rate of all Three Forks wells drilled west of the Nesson Anticline.

THREE / ***Drill our first Bakken well on our 83,500 net acres in Montana, which could potentially begin to delineate an additional 195 net Bakken drilling locations.***

Despite not efficiently completing the wells given that we did not get the liners all the way into the laterals, we completed our first two operated Montana Bakken wells, the Rogney and the Swindle, at 24-hour peak rates of 909 and 1,065 barrels of oil equivalent.

In early 2011, we successfully completed the Johnson 30-19 #1H, which commenced production at a 24-hour peak rate of 2,962 barrels of oil equivalent.

FOUR / ***Further expand our acreage position in our core Williston Basin project areas.***

During 2010 we grew our core Williston Basin acreage position approximately 86,000 net acres, or 30%, to 364,300 net acres.

2007 IN THE WB

- Acquired initial leases in Easy Rider (Mountrail County, ND)
- Commenced short lateral, multi-stage drilling
- 143,000 net acres at year-end
- 3.9 net wells drilled

FIVE / ***Implement Rough Rider and Ross project area support infrastructure projects to reduce both lease level operating expenses and drilling and completion costs.***

We invested $33 million in support infrastructure for gathering our crude oil and produced water and bringing our fresh water to our drilling wells, which will contribute to lower costs to drill, complete and produce our wells for years to come.

SIX / ***Continue to innovate drilling and completion designs to reduce drilling days and enhance production and EURs.***

We continued to lead the way for industry. We have now completed 59 wells in North Dakota with an industry leading average 24-hour peak rate of 2,860 barrels of oil equivalent. Our well performance continues to improve as our staff innovates, further advancing technology in the play.

SEVEN / ***Achieve 125% oil production volume growth in 2010 to approximately 5,200 barrels of oil per day. As a result, we expect our oil volumes to represent approximately 70% of our total production volumes for 2010. Our longer term goal is to double our oil production volumes in 2011 to an average of approximately 10,400 barrels of oil per day.***

Our 2010 oil production exceeded our goals by growing 167% in 2010 to average 6,155 barrels of oil per day. Our 2010 oil volumes represented 74% of our total production volumes.

Further, we are forecasting that our 2011 oil production should approximately double, and that our total equivalent production volumes should average 15,000 barrels of oil equivalent per day, both of which would exceed our previously announced goals for 2011.

EIGHT / ***Continue to seek opportunities to bring forward a portion of the very substantial inventory of drilling locations to further grow our net asset value per share.***

Early in 2011 we announced plans to further accelerate our drilling by adding an additional rig every four months, thereby increasing our Williston Basin drilling rigs from eight at May 2011 to a planned twelve rigs by September 2012.

OTHER NOTABLE 2010 ACHIEVEMENTS >

NINE / We successfully executed an equity offering in April 2010, raising approximately $289 million in proceeds. We also completed a bond offering in September 2010, which raised approximately $300 million in proceeds. Both offerings are anticipated to help us to build to eight operated drilling rigs in May 2011, and then to twelve rigs by May 2012.

TEN / Based on publicly available data, we have completed the top four, and seven of the top ten, highest early peak rate wells in the Williston Basin, led by our Sorenson 29-32 #2H, which commenced production at a 24-hour peak rate of 5,330 barrels of oil equivalent.

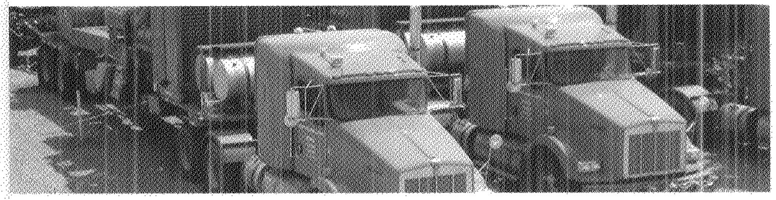
ELEVEN / Based on publicly available data, we have completed the eight highest early peak rate wells west of the Nesson Anticline, led by our Knoshaug 14-11 #1H, which commenced production at a 24-hour peak rate of 4,443 barrels of oil equivalent.

TWELVE / Our drilling success in the oil rich Williston Basin has resulted in our production transitioning from 80% natural gas three years ago to 80% oil during the fourth quarter of 2010. In the fourth quarter of 2010, our oil production represented 91% of our combined revenues.

THIRTEEN / During 2010 we grew our proved reserves 141% to a company record 66.8 million barrels of oil equivalent. Our Williston Basin reserves grew 260% during the year to 55.4 million barrels of oil equivalent. Furthermore, our reserves at year-end 2010 were 78% oil. We achieved a Total Proved Finding Cost of $9.23 per barrel of oil equivalent, excluding revisions, and a Proved Developed Drilling Cost for our operated Williston Basin Bakken and Three Forks wells of $15.57 per barrel of oil equivalent.

2008 IN THE WB

- Drilled first short lateral, twelve frac stage well in Easy Rider with 1,110 Boe IP
- Drilled first short lateral Three Forks well in Easy Rider with 892 Boe IP
- Drilled first multi-frac stage well in Rough Rider with 727 Boe IP
- 302,000 net acres at year-end
- 8.7 net wells drilled



> *"Our Williston Basin reserves grew 260% during the year to 55.4 million barrels of oil equivalent."*

FOURTEEN / Importantly, after commencing the year with our stock at approximately $13.55 per share, we exited 2010 with our stock at $27.24 per share, generating a return of approximately 100% as a result of our hard work, technological innovation and disciplined execution.

2011 GOALS >

FURTHER ACCELERATE ***our Williston Basin Bakken and Three Forks operated drilling program, providing us with the potential to drill up to 1,263 remaining net development locations on our current core acreage position over a reduced time frame.***

Increase our operated rigs running in the basin from seven to twelve by May 2012, adding a new operated rig roughly every four months.

Invest approximately $693 million in exploration and development capital.

FURTHER DELINEATE THREE FORKS ***drilling economics on our 159,900 net acre Rough Rider project area, where we could drill approximately 500 net potential Three Forks locations.***

Other operators have drilled discoveries proximal to our acreage.

Our operated State 36-1 #2H, which commenced production at a 24-hour peak rate of 2,356 barrels of oil equivalent, is the highest initial rate Three Forks well west of the Nesson Anticline.

FURTHER DELINEATE BAKKEN ***drilling economics on our 98,400 net acres in Montana, which could further de-risk up to an additional 307 net Bakken drilling locations.***

Other operators are very active drilling and completing wells in the area.

Our Johnson 30-18 #1H produced at a 24-hour peak rate of 2,965 barrels of oil equivalent, the apparent highest peak production rate for the Bakken in Montana to date.

FURTHER EXPAND ***our acreage position in our core Williston Basin project areas.***

In 2010 we grew our de-risked core acreage by roughly 45% to 205,300 net acres. Additional leasing and trades working should grow our position further.

COMPLETE ***Rough Rider and Ross project area infrastructure projects that will begin to reduce both lease level operating costs and well AFEs as early as late 2011.***

CONTINUE ***to innovate drilling and completion designs to reduce drilling days and enhance production and EURs.***

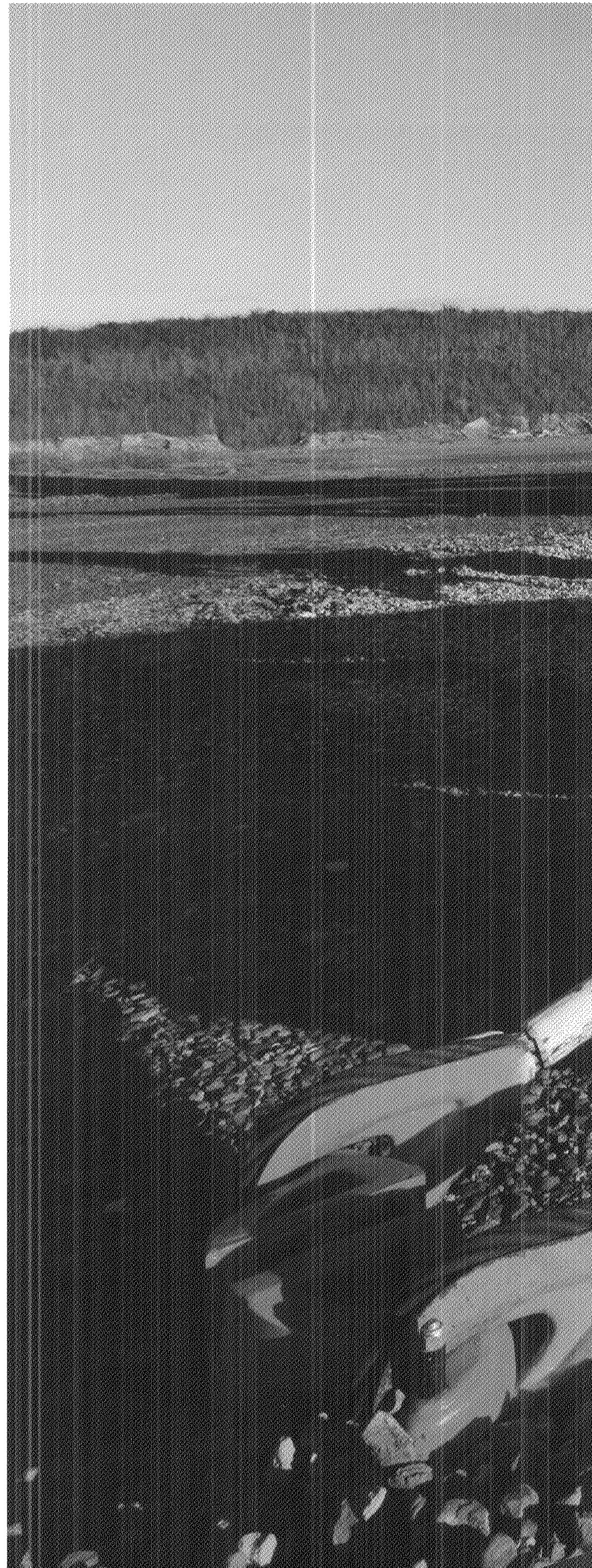
ACHIEVE 100% ***oil production volume growth in 2011 to approximately 12,300 barrels of oil per day.***

As a result, we expect our oil volumes to represent approximately 82% of our total production volumes for 2011.

CONTINUE TO SEEK ***opportunities to bring forward a portion of the very substantial inventory of drilling locations to further grow our net asset value.***

2009 IN THE WB

- First operator in the Williston Basin to drill long lateral, high frac stage wells
- Completed nine long lateral, high frac stage wells with 2,066 Boe average IP
- Delineated highly attractive Rough Rider economics with long lateral, high frac stage wells
- 282,600 net acres at year-end
- 6.9 net wells drilled



IN SUMMATION >

Although we are just getting started, we have already undergone a remarkable and dramatic transformation.

In a matter of a few years, Brigham Exploration has become a leading oil resource developer in the premier resource play in North America, the Williston Basin. Further, we are very proud of the fact that we are working together with all of our business partners and the great people of North Dakota and Montana, and "TOGETHER WE'RE FINDING OIL IN AMERICA, FOR AMERICANS™."

All of this would not have been possible were it not for our outstanding employees. They are the ones who have made this all happen. As they continue to execute, and we continue to accelerate the pace at which we convert our 12 to 20 year current inventory of de-risked drilling locations to reserves and cash flow, we will continue to innovate with ever improving technologies in striving for "NO OIL LEFT BEHIND™."

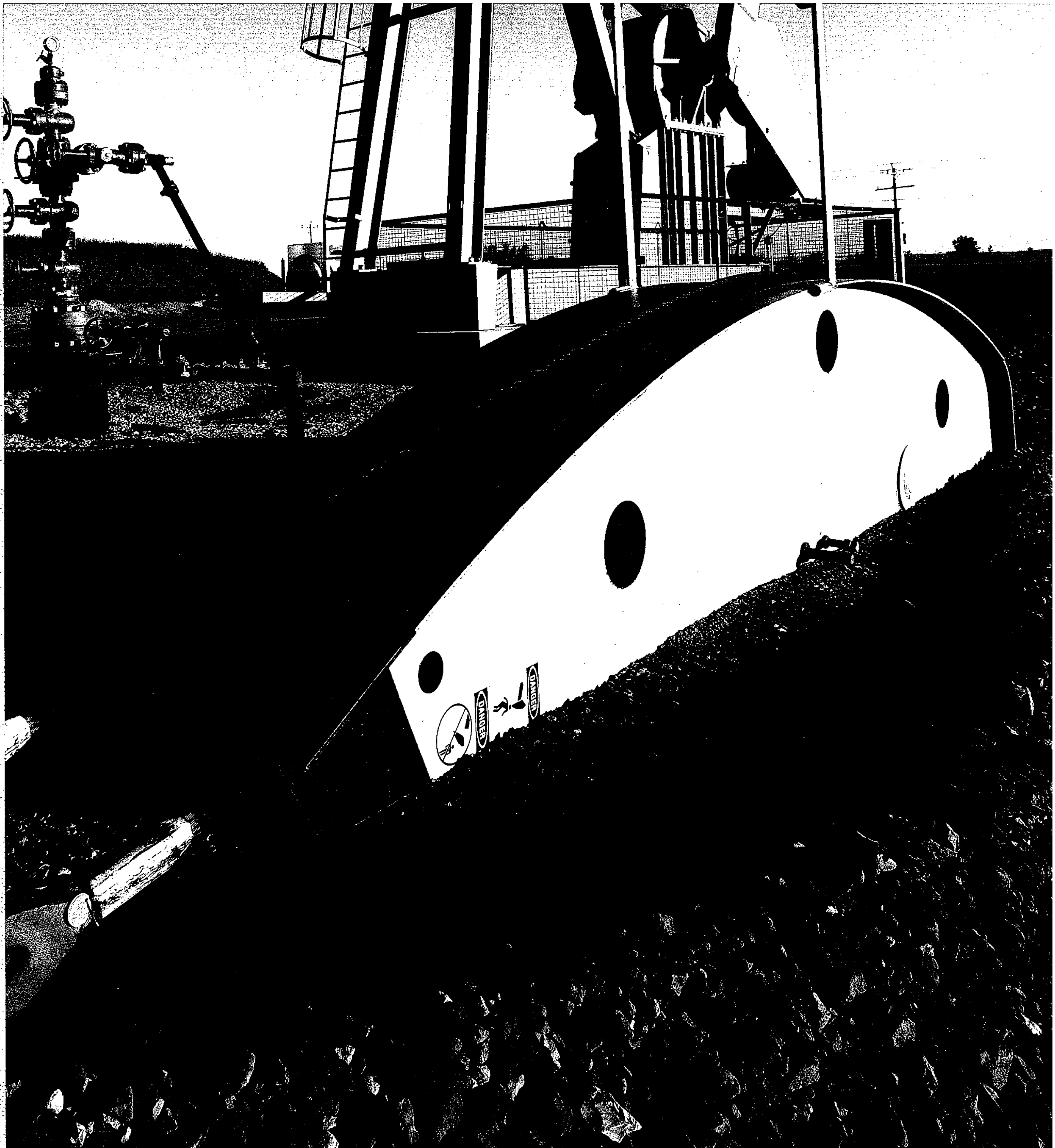
I want to personally thank our employees for their unwavering dedication and hard work. I also want to thank our loyal business partners and our stockholders. To all of you, I say "THANK YOU." We look forward to reporting on what should be another very memorable year for all of us.

B.M.B.

BEN "BUD" M. BRIGHAM
Chairman of the Board,
President & CEO
May 5, 2011

2010 IN THE WB

- Drilled record Williston Bakken well with 5,133 Boe IP
- Completed first Rough Rider Three Forks well with 2,356 Boe IP
- Drilled first Bakken well in Eastern Montana with 909 Boe IP
- $425 million in capex in 2010, including support infrastructure
- 364,300 net acres at year-end
- 38 net wells drilled



PLANNED 2011 IN THE WB

- Drilled record Williston Basin well with 5,330 Boe IP
- Drilled record Rough Rider Bakken well with 4,443 Boe IP
- Announced infill drilling opportunity with four Bakken and four Three Forks wells per spacing unit
- Plan to spend $692 million in capex
- Anticipate completing construction of 433 miles of support infrastructure pipeline
- Plan to drill 66 net horizontal Bakken and Three Forks wells in 2011

year end financial highlights

OPERATING DATA	2010	2009	2008	2007	2006
Revenue from the sale of oil & natural gas	$ 182, 897	$ 77,569	$ 121,516	$ 124,724	$ 103,590
Unrealized hedging gains (losses)	(13,175)	(7,313)	6,140	(5,831)	2,580
Total revenue	169,722	70,344	127,788	118,981	106,297
Operating income (loss)	60,444	(108,916)	(191,174)	29,884	36,448
Net cash provided (used) by operating activities	144,520	51,750	69,630	90,449	88,687
Net income (loss) to common stockholders	42,896	(122,992)	(162,247)	10,210	19,788

PER DILUTED SHARE DATA					
Weighted average shares outstanding	113,308	70,569	45,441	45,531	45,597
Net income (loss) per share	$ 0.38	$ (1.74)	$ (3.57)	$ 0.22	$ 0.43

OIL & NATURAL GAS CAPITAL EXPENDITURE DATA					
Net drilling	$ 280,080	$ 58,209	$ 136,248	$ 96,833	$ 142,338
Support infrastructure	33,226	-	-	-	-
Land	112,153	1,761	35,796	17,527	31,683
Capitalized G&A and interest	21,470	12,432	12,852	11,631	9,954
Asset retirement obligations	814	327	412	325	609
Total	$ 447,743	$ 72,729	$ 185,308	$ 126,316	$ 184,584

SUMMARY BALANCE SHEET DATA					
Cash, cash equivalents & short term investments	$ 247,734	$ 120,874	$ 40,598	$ 13,863	$ 4,300
Oil & natural gas properties, net	669,356	330,733	404,839	510,207	485,525
Total assets	1,085,401	498,256	489,056	548,428	522,587
Total debt	300,000	158,968	303,730	168,492	149,334
Series A preferred stock	-	10,101	10,101	10,101	10,101
Stockholders' equity	593,270	264,283	121,269	279,027	266,015

PER BOE DATA					
Revenue from the sale of oil & natural gas	$ 57.43	$ 39.12	$ 66.84	$ 49.98	$ 46.92
Support infrastructure revenue	0.17	-	-	-	-
Other revenue	0.01	0.05	0.06	-	0.06
Total revenue	$ 57.61	$ 39.17	$ 66.90	$ 49.98	$ 46.98
Lease operating expenses	6.33	8.16	6.48	4.26	4.86
Production taxes	5.88	2.84	2.82	1.02	1.80
G&A expenses	4.39	5.15	4.98	3.72	3.60
Gross profit per Boe	$ 41.01	$ 23.02	$ 52.62	$ 40.98	$ 36.72

[IN THOUSANDS, EXCEPT PER SHARE AND PER BOE DATA]

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

Form 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2010

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: 001-34224

Brigham Exploration Company

(Exact name of Registrant as Specified in its Charter)

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

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

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

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $0.01 par value	NASDAQ Global Select Market

Securities registered pursuant to Section 12(g) of the Act:
None
(Title of Class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12-b of the Act). Yes ☐ No ☑

As of June 30, 2010, the registrant had 116,596,688 shares of voting common stock outstanding. The aggregate market value of the registrant's outstanding shares of voting common stock held by non-affiliates, based on the closing price of these shares on June 30, 2010 of $15.38 per share as reported on The NASDAQ Global Select Market, was $1.7 billion. Shares held by each executive officer and director and by each person who owns 10% or more of the outstanding common stock are considered affiliates. The determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of February 23, 2011, the registrant had 116,968,942 shares of voting common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the Registrant's 2011 Annual Meeting of Stockholders to be held on June 21, 2011, 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, 2010.

BRIGHAM EXPLORATION COMPANY

TABLE OF CONTENTS

BRIGHAM EXPLORATION COMPANY

2010 ANNUAL REPORT ON FORM 10-K

PART I

Item 1. *Business*

Overview

We are an independent exploration, development and production company that utilizes advanced exploration, drilling and completion technologies to systematically explore for, develop and produce domestic onshore crude oil and natural gas reserves. We focus our activities in provinces where we believe these technologies, including horizontal drilling, multi-stage isolated fracture stimulations and 3-D seismic imaging, can be used to effectively maximize our return on invested capital.

Historically, our exploration and development activities have been focused in our Onshore Gulf Coast, the Anadarko Basin and West Texas and Other provinces. However, in late 2007, the majority of our drilling capital expenditures shifted from our historically active areas to the Williston Basin, where we are currently targeting the Bakken, Three Forks and Red River objectives. As of December 31, 2010, we had approximately 600,601 gross and 364,309 net leasehold acres in the Williston Basin. Through year-end 2010, we have invested in excess of $625 million on drilling, land and support infrastructure in this province.

At December 31, 2010, our proved reserves totaled 66.8 million barrels of oil equivalent (MMBoe) and had a standardized measure of $866.1 million and a pre-tax PV10% value of $1.1 billion. Approximately 78% of our proved reserves are crude oil and we operate approximately 81% of our proved reserves. Our average production volumes for 2010 were 8,267 barrels of oil equivalent per day (Boepd), which represents a 64% increase from 2009.

The following table provides information regarding our assets and operations located in our core areas.

	At December 31, 2010					2010
				Productive Wells		Average Daily Production
Province	Proved Reserves(a) (MMBoe)	Pre-Tax PV10%(b)(c) (Millions)	% Oil	Gross	Net	Volumes (d) (Boe)
Williston Basin	55.5	$ 939.4	89%	237	61.0	6,146
Onshore Gulf Coast	7.6	127.7	21%	85	44.5	1,394
Anadarko Basin	2.6	22.1	7%	89	23.6	558
West Texas and Other	1.1	19.5	87%	31	7.6	169
Total	66.8	$ 1,108.7	78%	442	136.7	8,267

(a) MMBoe is defined as one million barrels of oil equivalent determined using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids.

(b) The prices used to calculate this measure were $79.43 per barrel of crude oil and $4.376 per MMbtu of natural gas. The prices represent the average prices per barrel of crude oil and per MMbtu of natural gas at the beginning of each month in the 12-month period prior to the end of the reporting period. These prices were adjusted to reflect applicable transportation and quality differentials on a well-by-well basis to arrive at realized sales prices used to estimate our reserves at this date.

(c) The standardized measure for our proved reserves at December 31, 2010 was $866.1 million. See "Item 2. Properties — Reconciliation of Standardized Measure to Pre-tax PV10%" for a definition of pre-tax PV10% and a reconciliation of our standardized measure to our pre-tax PV10% value.

(d) Average daily production volumes calculated based on 360 day year. Average daily production volumes include approximately 29,654 barrels of oil produced during 2010 and recorded as inventory at year-end 2010. Total oil inventory at year-end 2010 and 2009 was 46,129 and 16,475 barrels of crude oil, respectively. Total crude oil inventory at year-end 2008 was not material. Adjusting production volumes for amounts included in inventory would result in average daily sales volumes in 2010 and 2009 of 8,185 and 4,988 barrels of oil per day.

Since inception we have drilled and completed, or are currently in the process of drilling or completing 1,075 gross wells, consisting of 525 exploration and 550 development wells with an average completion rate of 77%. Over the three year period ended December 31, 2010, we drilled and completed, or were in the process of drilling or completing 315 gross wells, consisting of 10 exploratory and 305 development wells with an average completion rate of 99%. Our improved completion rate over the past three years is attributable to our increased level of activity in the Williston Basin, which is an unconventional resource play that generally provides more predictable drilling results. During 2010, we drilled and completed or were currently in the process of drilling or completing 193 gross wells, consisting of one exploratory well and 192 development wells with a completion rate of 100%. Both our higher levels of development drilling and completion rate in 2010, as compared to prior years, are also attributable to our increased level of activity in the Williston Basin.

Over the three year period ended December 31, 2010, we spent approximately $474.5 million on drilling capital expenditures, $162.9 million on land, prior to proceeds from asset sales, and $33.2 million on support infrastructure. Approximately 88% of our total drilling, land, seismic and support infrastructure spending over this three year period, prior to proceeds from asset sales, was spent in the Williston Basin.

In 2010, we spent approximately $280.1 million on drilling capital expenditures, which represents a 381% increase from that in 2009. The increase was a result of our limited drilling activity during the first half of 2009 as a result of the global financial recession that severely depressed commodity prices. As economic conditions improved, we issued equity in October 2009 and April 2010 to increase our operated drilling activity in the Williston Basin to four operated drilling rigs by year-end 2009 and to seven operated drilling rigs by year-end 2010. This increase in our operated drilling rig count resulted in higher levels of drilling capital expenditures during 2010. In 2010, we spent approximately $113.5 million on land, prior to proceeds from asset sales, which represents a 1,002% increase from that in 2009. Our higher level of land expenditures was primarily driven by the acquisition of approximately 81,725 net acres in the Williston Basin during 2010. In 2010, we spent approximately $33.2 million on support infrastructure, which includes oil, natural gas, produced water and fresh water gathering lines primarily in Williams and Mountrail Counties, North Dakota. We also drilled two water disposal wells and began construction on a regional office in Williston, North Dakota. These expenditures were incurred in order to more effectively and efficiently manage our rapidly growing operations in the Williston Basin. In earlier periods, we did not incur material support infrastructure costs.

In 2011, we anticipate spending approximately $582.1 million on drilling capital expenditures, $27.4 million on land and $83.2 million on support infrastructure. The increase in our drilling capital expenditure budget is a result of our continued acceleration of drilling activity in the Williston Basin. We began 2011 with seven operated drilling rigs and anticipate adding an eighth operated drilling rig in May 2011 and another operated drilling rig in September 2011. Further, our plans are to add an additional operated rig every four months until we reach 12 rigs by September 2012.

Lower land and seismic costs are anticipated as acquisition activity is expected to be more competitive in 2011 as compared to 2010. Our support infrastructure costs are anticipated to increase in 2011, as we expand construction of gathering lines in Williams County and begin to construct gathering lines in McKenzie County, North Dakota and drill additional water disposal wells.

Our 2011 budget is anticipated to be funded with cash and short term investments on hand as of year-end 2010, cash flow from operations, the proceeds from potential conventional oil and gas asset sales and availability under our Fifth Amended and Restated Credit Agreement that closed on February 23, 2011, which had no amounts outstanding and a $325 million borrowing base.

Business Strategy

Our business strategy is to create value for our stockholders by growing reserves, production and cash flow utilizing advanced exploration, drilling and completion technologies to systematically explore for, develop and produce domestic onshore crude oil and natural gas reserves. Key elements of our business strategy include:

- *Focus on Net Asset Value Creation in our Provinces.* We plan to concentrate the majority of our near term capital expenditures in the Williston Basin, where we believe our approximately 364,309 net acres and the application of advanced drilling and completion techniques provide us with a significant competitive advantage in developing the significant net asset value associated with both the Bakken and Three Forks producing horizons. In addition to the Williston Basin, we have a multi-year drilling prospect inventory in the following three provinces: Onshore Gulf Coast, Anadarko Basin and West Texas. Our projects in these provinces provide us with important future drilling investment diversification.

- *Leverage our Engineering and Operational Expertise.* Our staff is highly proficient with state-of-the-art drilling and completion techniques, including directional drilling, horizontal drilling and multi-stage isolated fracture stimulations. Our drilling and completion techniques in the Williston Basin have rapidly evolved from drilling and completing long lateral wells with single large uncontrolled fracture stimulations in late 2006 to drilling and completing long lateral wells with 20 isolated fracture stimulation stages in early 2009. During 2010, we typically drilled and completed our long lateral wells with between 30 and 38 isolated fracture stimulation stages and made other changes to our drilling and completion formula. We will continue to refine our drilling and completion techniques in order to attempt to enhance the performance and the associated estimated ultimate recoveries and net asset value of our wells.

- *Capitalize on Internally Generated Exploration Successes Through Disciplined Development Activities.* From 1990 to 1999, we grew our reserves and production volumes primarily through successful exploration drilling. In recent years, our exploratory drilling success has generated a multi-year inventory of development drilling locations. We have a 20 year track record of successfully generating and drilling exploration wells in new oil and natural gas plays. We are particularly interested in those plays with attractive exploration and development potential that complement our current exploration, development and production activities. After identifying such a play, we will often selectively build an acreage position in the play. Our current inventory of drilling locations in the Williston Basin and the Vicksburg and Hunton plays in our Onshore Gulf Coast province are examples of successful projects where our position in the play was internally identified and originated.

- *Enhance Returns Through Operational Control.* We typically leverage our technical and operational expertise by seeking to maintain operational control of our exploration and drilling activities. As operator, we retain more control over the timing, selection and process of drilling prospects, which enhances our ability to maximize our return on invested capital. Since we generate most of our own projects, we generally have the ability to retain operational control over all phases of our exploration, development and production activities. Furthermore, retaining operational control gives us the ability to control the financing, construction and operation of infrastructure related to our production operations such as crude oil, natural gas and wastewater gathering and processing, which in certain situations can enhance our well and project economics.

Exploration and Land Staff

Our experienced exploration staff includes 12 geologists, five geophysicists, two computer applications specialists and five geological technicians. Our geologists and geophysicists have varied, but complementary backgrounds. Their diversity of experience in a wide-range of geological and geophysical settings, combined with various technical specializations (from hardware and systems to software and seismic data processing), provides us with valuable technical, intellectual resources. Our geologists and geophysicists have an average of more than 20 years of experience in the industry. We have assembled our team of geologists and geophysicists with backgrounds that complement the areas where we focus our exploration and development activities. By integrating both geologic and geophysical expertise within our project teams, we believe we possess a competitive advantage in our exploration approach.

Our land department staff includes six landmen with an average of more than 17 years of experience, primarily within our core provinces, and seven lease and division order analysts. Our land department contributed to pioneering many of the innovations that have facilitated exploration using large 3-D seismic projects.

Operations Staff

In an effort to retain better control of our project timing, drilling, operational costs and production volumes, we attempt to operate as many of the wells we drill as possible. We operated approximately 29% of the gross wells and 81% of the net wells that we drilled during 2010, as compared with 10% of the gross wells and 17% of the net wells we drilled during 1996. In 2011, we anticipate we will operate an increased number of wells as we currently have seven operated drilling rigs running in the Williston Basin and, subject to commodity price risk, service costs and other factors, anticipate increasing our operated drilling rig count to nine rigs by September 2011. As a result of our increased operational control, wells operated by us constituted 81% of our proved reserves at year-end 2010, as compared to only 5% at year-end 1996.

Our operations staff includes ten engineers with an average of more than 13 years of experience in drilling, reservoir, operations or environmental engineering primarily within our four core operating provinces. These engineers work closely with our geologists and geophysicists and are integrally involved in all phases of the exploration and development process, including preparation of pre- and post-drill reserve estimates, well design, production management and analysis of full cycle risked drilling economics. We conduct field operations for our operated oil and natural gas properties through a combination of our field and third party contract personnel. As of year-end 2010, we had three employees located in North Dakota and anticipate opening a regional office in Williston, North Dakota in the second quarter 2011 in order to more effectively and efficiently manage our operations in the Williston Basin.

Crude Oil and Natural Gas Market and Major Customers

In an effort to improve price realizations from the sale of our crude oil and natural gas, we manage our commodities marketing activities in-house, which enables us to market and sell our crude oil and natural gas to a broader universe of potential purchasers. Due to the availability of other markets and pipeline connections, we do not believe that the loss of any single crude oil or natural gas customer would have a material adverse effect on our results of operations or cash flows.

We sell our crude oil and condensate at the lease to a variety of purchasers at prevailing market prices under short-term contracts that normally provide for us to receive a market based price, which incorporates regional differentials that include but are not limited to transportation costs and adjustments for product quality. See "Item 2. Properties — Delivery Commitments."

Our natural gas production is sold to various purchasers including intrastate pipeline purchasers, operators of processing plants, and marketing companies under both monthly spot market contracts and multi-year arrangements. The vast majority of our natural gas sales are based on related natural gas index pricing. In some cases, our gas is processed at a plant and we receive a percentage of the value the plant operator receives from the resale of the natural gas liquids recovered and the remaining residue gas. See "Item 2. Properties — Delivery Commitments."

Since most of our crude oil and natural gas production is sold under price sensitive or spot market contracts, the revenues generated by our operations are highly dependent upon the prices of and demand for crude oil and natural gas. The price we receive for our crude oil and natural gas production depends upon numerous factors beyond our control, including but not limited to seasonality, weather, competition, the condition of the United States economy, foreign imports, political conditions in other crude oil-producing and natural gas-producing countries, the actions of the Organization of Petroleum Exporting Countries, and domestic government regulation, legislation and policies. See "Item 1A. Risk Factors — Crude oil and natural gas prices are volatile and thus could be subject to further reduction, which would adversely affect our results and the price of our common stock." Furthermore, a decrease in the price of crude oil and natural gas could have an adverse effect on the carrying value of our proved reserves and on our revenues, profitability and cash flow. See "Item 1A. Risk Factors — Lower crude oil and natural gas prices may cause us to record ceiling limitation writedowns, which would reduce our stockholders' equity."

Although we are not currently experiencing any significant involuntary curtailment of our crude oil or natural gas production, market, economic and regulatory factors may in the future materially affect our ability to sell our crude oil or natural gas production. See "Item 1A. Risk Factors — The marketability of our crude oil and natural gas production depends on services and facilities that we typically do not own or control. The failure or inaccessibility of any such services or facilities could affect market based prices or result in a curtailment of production and revenues."

Competition

The oil and natural gas industry is highly competitive in all phases. We encounter competition from other oil and natural gas companies in all areas of operation, including the acquisition of seismic and leasing options on oil and natural gas properties to the exploration and development of those properties. Our competitors include major integrated oil and natural gas companies, numerous independent oil and natural gas companies, individuals and drilling and income programs. Many of our competitors are large, well established companies that have substantially larger operating staffs and greater capital resources than we do. Such companies may be able to pay more for seismic and lease options on oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. See "Item 1A. Risk Factors — We face significant competition and many of our competitors have resources in excess of our available resources."

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 the new wells we drill will be productive or that we will recover all or any portion of our investment. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells, but also from wells that are productive, but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. The cost and timing of drilling, completing and operating wells is often uncertain. Our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, many of which are beyond our control, including low crude oil and natural gas prices, title problems, weather conditions, delays by project participants, compliance with governmental requirements, shortages or delays in the delivery of equipment and services and increases in the cost for such equipment and services. Our future drilling activities may not be successful and, if unsuccessful, such failure may have a material adverse effect on our business, financial condition, results of operations and cash flows. See "Item 1A. Risk Factors — Our exploration, development and drilling efforts and the operation of our wells may not be profitable or achieve our targeted returns", "Item 1A. Risk Factors — Exploratory drilling is a speculative activity that may not result in commercially productive reserves and may require expenditures in excess of budgeted amounts", "Item 1A. Risk Factors — Although our oil and natural gas reserve data is independently estimated, these estimates may still prove to be inaccurate" and "Item 1A. Risk Factors — The lack of availability or high cost of drilling rigs, equipment, supplies, insurance, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget."

Our operations are subject to hazards and risks inherent in drilling for and producing and transporting crude oil and natural gas, such as fires, natural disasters, explosions, encountering formations with abnormal pressures, blowouts, craterings, pipeline ruptures and spills, any of which can result in the loss of hydrocarbons, environmental pollution, personal injury claims and other damage to our properties and those of others. We maintain insurance against some but not all of the risks described above. In particular, the insurance we maintain does not cover claims relating to failure of title to oil and natural gas leases, loss of surface equipment at well locations, trespass during 3-D survey acquisition or surface damage attributable to seismic operations, business interruption, loss of revenue due to low commodity prices or loss of revenues due to well failure. Furthermore, in certain circumstances in which insurance is available, we may not purchase it. The occurrence of an event that is not covered, or not fully covered by insurance could have a material adverse effect on our business, financial condition, results of operations and cash flows in the period such event may occur. See "Item 1A. Risk Factors — We are subject to various operating and other casualty risks that could result in liability exposure or the loss of production and revenues" and "Item 1A. Risk Factors — We may not have enough insurance to cover all of the risks we face, which could result in significant financial exposure."

Governmental Regulation

Our crude oil and natural gas exploration, production, transportation and marketing activities are subject to extensive laws, rules and regulations promulgated by federal and state legislatures and agencies, including but not limited to the Federal Energy Regulatory Commission (FERC), the Environmental Protection Agency (EPA), the Bureau of Land Management (BLM), the Texas Commission on Environmental Quality (TCEQ), the Texas Railroad Commission (TRRC), the Louisiana Department of Natural Resources (LDNR), the Industrial Commission of North Dakota (NDIC), the Oklahoma Corporation Commission (OCC), the Montana Board of Oil and Gas Conservation (MBOGC) and similar type commissions within these states and of the other states in which we do business. Failure to comply with such laws, rules and regulations can result in substantial penalties, including the delay or stopping of our operations. The legislative and regulatory burden on the oil and natural gas industry increases our cost of doing business and affects our profitability. See "Item 1A. Risk Factors — We are subject to various governmental regulations and environmental risks that may cause us to incur substantial costs."

Although we do not own or operate any pipelines or facilities that are directly regulated by FERC, its regulation of third party pipelines and facilities could indirectly affect our ability to transport or market our production. Moreover, FERC has in the past, and could in the future, impose price controls on the sale of natural gas. We believe we are in substantial compliance with all applicable laws and regulations; however, we are unable to predict the future cost or impact of complying with such laws and regulations because they are frequently amended, interpreted and reinterpreted.

The states of Texas, Oklahoma, Louisiana, North Dakota, Montana and most other states, as well as the federal government when operating on federal or Indian lands, require permits for drilling operations, drilling bonds and reports concerning operations and impose other requirements relating to the exploration and production of crude oil and natural gas. These governmental authorities also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of crude oil and natural gas properties, the establishment of maximum rates of production from wells and the regulation of spacing, plugging and abandonment of such wells.

Environmental Matters

Our operations and properties are, like the oil and natural gas industry in general, subject to extensive and changing federal, state and local laws and regulations relating to both environmental protection, including the generation, storage, handling, emission, transportation and discharge of materials into the environment, and safety and health. The recent trend in environmental legislation and regulation is generally toward stricter standards, and this trend is likely to continue. These laws and regulations may require a permit or other authorization before construction or drilling commences and for certain other activities; limit or prohibit access, seismic acquisition, construction, drilling and other activities on certain lands lying within wilderness and other protected areas; impose substantial liabilities for pollution resulting from our operations; and require the reclamation of certain lands.

The permits required for many of our operations are subject to revocation, modification and renewal by issuing authorities. Governmental authorities have the power to enforce compliance with their regulations, and violations are subject to fines, injunctions, or both. In the opinion of management, we are in substantial compliance with current applicable environmental laws and regulations, and we have no material commitments for capital expenditures to comply with existing environmental requirements. Nevertheless, changes in existing environmental laws and regulations or in interpretations thereof could have a significant impact on us, as well as the oil and natural gas industry in general. The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) and comparable state statutes impose strict and arguably joint and several liabilities on owners and operators of certain sites and on persons who disposed of or arranged for the disposal of "hazardous substances" found at such sites. It is not uncommon for the neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. The Resource Conservation and Recovery Act (RCRA) and comparable state statutes govern the disposal of "solid waste" and "hazardous waste" and authorize imposition of substantial fines and penalties for noncompliance. Although CERCLA currently excludes petroleum from its definition of "hazardous substance," state laws affecting our operations impose clean-up liability relating to petroleum and petroleum related products. In addition, although RCRA classifies certain oil field wastes as "non-hazardous," such exploration and production wastes could be reclassified as hazardous wastes, thereby making such wastes subject to more stringent handling and disposal requirements.

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

In addition to the aforementioned regulatory agencies, there are various federal and state programs that regulate conservation and development of coastal resources. The federal Coastal Zone Management Act (CZMA) was passed to preserve and, where possible, restore the natural resources of the United States' coastal zone. The CZMA provides for federal grants for the state management programs that regulate land use, water use and coastal development.

The Texas Coastal Coordination Act (CCA) provides for coordination among local and state authorities to protect coastal resources through regulating land use, water, and coastal development and establishes the Texas Coastal Management Program that applies in the nineteen counties that border the Gulf of Mexico and its tidal bays. The CCA provides for the review of state and federal agency rules and agency actions for consistency with the goals and policies of the Coastal Management Plan. This review may affect agency permitting and may add a further regulatory layer to some of our projects.

The Louisiana Coastal Zone Management Program (LCZMP) was established to protect, develop and, where feasible, restore and enhance coastal resources of the state. Under the LCZMP, coastal use permits are required for certain activities, even if the activity only partially infringes on the coastal zone. Among other things, projects involving use of state lands and water bottoms, dredge or fill activities that intersect with more than one body of water, mineral activities, including the exploration and production of crude oil and natural gas, and pipelines for the gathering, transportation or transmission of crude oil, natural gas and other minerals require such permits. General permits, which entail a reduced administrative burden, are available for a number of routine oil and gas activities. The LCZMP and its requirement to obtain coastal use permits may result in additional permitting requirements and associated project schedule constraints.

See "Item 1A. Risk Factors — We are subject to various governmental regulations and environmental risks that may cause us to incur substantial costs."

Climate Change

Climate change has become the subject of an important public policy debate. Climate change remains a complex issue, with some scientific research suggesting that an increase in greenhouse gas emissions (GHGs) may pose a risk to society and the environment. The oil and natural gas exploration and production industry is a source of certain GHGs, namely carbon dioxide and methane, and future restrictions on the combustion of fossil fuels or the venting of natural gas could have a significant impact on our future operations. See "Item 1A. Risk Factors — The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the crude oil and natural gas we produce."

Impact of Legislation and Regulation. The commercial risk associated with the exploration and production of fossil fuels lies in the uncertainty of government-imposed climate change legislation, including cap and trade schemes, and regulations that may affect us, our suppliers, and our customers. The cost of meeting these requirements may have an adverse impact on our financial condition, results of operations and cash flows, and could reduce the demand for our products.

Climate change legislation and regulations have been adopted by many states in the US. However, legislation has not been enacted at the federal level in the US. The 111th Congress considered a number of bills designed to regulate green house gas emissions, but did not pass any of those bills. It is unclear whether the current Congress or a future Congress will take further action on green house gasses. But, several states are considering adopting climate change legislation. The current state of development of many state and federal climate change regulatory initiatives in areas where we operate makes it difficult to predict with certainty the future impact on us, including accurately estimating the related compliance costs that we may incur.

Indirect Consequences of Regulation or Business Trends. We believe there are risks arising from the global response to climate change. See "Item 1A. Risk Factors — The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the crude oil and natural gas we produce."

Physical Impacts of Climate Change on our Costs and Operations. There has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornados and snow or ice storms, as well as rising sea levels. Extreme weather conditions increase our costs, and damage resulting from extreme weather may not be fully insured. However, the extent to which climate change may lead to increased storm or weather hazards affecting our operations is difficult to identify at this time.

Formation

We were incorporated in the State of Delaware on February 25, 1997.

Facilities

Our principal executive offices are located in Austin, Texas, where we lease approximately 36,621 square feet of office space at 6300 Bridge Point Parkway, Building 2, Suite 500, Austin, Texas 78730. We also have a field office in Ross, North Dakota and plan to open a regional office in Williston, North Dakota in 2011.

Employees

As of December 31, 2010, we had 87 full-time employees and 2 part-time employees. As of the end of 2010, none of our employees were represented by labor unions and we believe relations with them are good.

Website Access

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

Item 1A. ***Risk Factors***

You should carefully consider the following risk factors, in addition to the other information set forth in this report. Each of these risk factors could adversely affect our business, operating results and financial condition.

Crude oil and natural gas prices are volatile and thus could be subject to further reduction, which would adversely affect our results and the price of our common stock.

Our revenues, operating results and future rate of growth depend highly upon the prices we receive for our crude oil and natural gas production. Historically, the markets for crude oil and natural gas have been volatile and are likely to continue to be volatile in the future.

The NYMEX daily settlement price for the prompt month crude oil contract during 2010 ranged from a high of $91.51 per barrel to a low of $68.01 per barrel. The NYMEX daily settlement price for the prompt month crude oil contract in 2009 ranged from a high of $81.37 per barrel to a low of $33.98 per barrel. In 2008, the same index ranged from a high of $145.29 per barrel to a low of $33.87 per barrel.

The NYMEX daily settlement price for the prompt month natural gas contract during 2010 ranged from a high of $7.51 per MMBtu to a low of $3.18 per MMBtu. The NYMEX daily settlement price for the prompt month natural gas contract in 2009 ranged from a high of $6.07 per MMBtu to a low of $2.51 per MMBtu. In 2008, the same index ranged from a high of $13.58 per MMBtu to a low of $5.29 per MMBtu.

The markets and prices for crude oil and natural gas depend on numerous factors beyond our control. These factors include demand for crude oil and natural gas, which fluctuate with changes in market and economic conditions and other factors, including:

- worldwide and domestic supplies of crude oil and natural gas;
- actions taken by foreign crude oil and natural gas producing nations;
- political conditions and events (including instability or armed conflict) in crude oil-producing or natural gas producing regions;
- the level of global and domestic crude oil and natural gas inventories;

- the price and level of foreign imports including liquefied natural gas imports;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the availability of pipeline or other takeaway capacity;
- weather conditions;
- domestic and foreign governmental regulations and taxes; and
- the overall worldwide and domestic economic environment.

Significant declines in crude oil and natural gas prices for an extended period may have the following effects on our business:

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

The ongoing economic uncertainty could negatively impact the prices for crude oil and natural gas, limit access to the credit and equity markets, increase the cost of capital, and may have other negative consequences that we cannot predict.

The ongoing economic uncertainty in the U.S. could create financial challenges if conditions do not improve. Our internally generated cash flow, our Senior Credit Facility and cash on hand historically have not been sufficient to fund all of our expenditures, and we have relied on the capital markets and sales of non-core assets to provide us with additional capital. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise capital. If our cash flow from operations is less than anticipated and our access to capital is restricted, we may be required to reduce our operating and capital budget, which could have a material adverse effect on our results and future operations. Ongoing uncertainty may also reduce the values we are able to realize in asset sales or other transactions we may engage in to raise capital, thus making these transactions more difficult to consummate and less economic. Additionally, demand for crude oil and natural gas may deteriorate and result in lower prices for crude oil and natural gas, which could have a negative impact on our revenues. Lower prices could also adversely affect the collectability of our trade receivables and cause our commodity hedging arrangements to be ineffective if our counterparties are unable to perform their obligations.

Our hedging activities may prevent us from benefiting from price increases and may expose us to other risks.

In an attempt to reduce our sensitivity to energy price volatility and in particular to downward price movements, we enter into hedging arrangements with respect to a portion of expected production, such as the use of derivative contracts that generally result in a range of minimum and maximum price limits or a fixed price over a specified time period. Our current strategy is to hedge up to 100% of our proved developed producing reserves and up to 50% of the incremental oil volumes associated with our Williston Basin drilling program over the next 24 months with costless collars and puts.

Our hedging activities expose us to the risk of financial loss in certain circumstances. For example, if we do not produce our crude oil and natural gas reserves at rates equivalent to our derivative position, we would be required to satisfy our obligations under those derivative contracts on potentially unfavorable terms without the ability to offset that risk through sales of comparable quantities of our own production. Additionally, because the terms of our derivative contracts are based on assumptions and estimates of numerous factors such as cost of production and pipeline and other transportation and marketing costs to delivery points, substantial differences between the prices we receive pursuant to our derivative contracts and our actual results could harm our anticipated profit margins and our ability to manage the risk associated with fluctuations in crude oil and natural gas prices. We also could be financially harmed if the counterparties to our derivative contracts prove unable or unwilling to perform their obligations under such contracts. Additionally, in the past, some of our derivative contracts required us to deliver cash collateral or other assurances of performance to the counterparties if our payment obligations exceeded certain levels. Future collateral requirements are uncertain but will depend on arrangements with our counterparties, highly volatile crude oil and natural gas prices and future rules and regulations to be promulgated by the Commodities Futures Trading Commission (the "CFTC") pursuant to the mandate of the United States Congress under the Dodd-Frank Wall Street Reform and Consumer Protection Act. See "— Derivatives regulation included in current financial reform legislation could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices."

The results of our planned drilling in the Bakken and Three Forks objectives, an emerging play with limited drilling and production history, are subject to more uncertainties than our drilling program in the more established formations and may not meet our expectations for reserves or production.

We have recently begun drilling wells in the Bakken and Three Forks objectives. Part of our drilling strategy to maximize the net asset value and recoveries from the Bakken and Three Forks objectives involves drilling horizontal wells using completion techniques that have proven successful in other shale formations. Our experience with drilling horizontal wells in the Bakken and Three Forks objectives to date, as well as the industry's drilling and production history in the formation, is limited. The ultimate success of these drilling and completion strategies and techniques in this formation will be better evaluated over time as more wells are drilled and longer term production profiles are established. In addition, based on reported decline rates in these formations in other areas and in other shale formations, we estimate the average monthly rates of production should decline by approximately 70% during the first twelve months of production. Actual decline rates may differ significantly. Accordingly, the results of our future drilling in the emerging Bakken and Three Forks objectives are more uncertain than drilling results in the other formations with established reserves and production histories.

Further, access to adequate gathering systems or pipeline takeaway capacity and the availability of drilling rigs and other services may be more challenging in new or emerging plays. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems and takeaway capacity or otherwise, and/or crude oil and natural gas prices are depressed, the return on our investment in these areas may not be as attractive as we anticipate and we could incur material writedowns of unevaluated properties and the value of our undeveloped acreage could decline in the future.

The lack of availability or high cost of drilling rigs, fracture stimulation crews, equipment, supplies, insurance, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, fracture stimulation crews, equipment, supplies, insurance or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. If levels of exploration and production increase in response to strong crude oil and natural gas prices, the demand for oilfield services will likely rise, and the costs of these services will likely increase, while at the same time the quality of these services may suffer. If the lack of availability or high cost of drilling rigs, equipment, supplies, insurance or qualified personnel were particularly severe in North Dakota, Montana, Texas, Southern Louisiana, or Oklahoma, we could be materially and adversely affected because our operations and properties are concentrated in those areas.

The proposed United States federal budgets for fiscal years 2011 and 2012 and proposed legislation contain certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.

The Obama administration's budget proposals for fiscal years 2011 and 2012 each contain numerous proposed tax changes, and from time to time, legislation has been introduced that would enact many of these proposed changes. The proposed budget and legislation would repeal many tax incentives and deductions that are currently used by U.S. oil and gas companies and impose new taxes. Among others, the provisions include: elimination of the ability to fully deduct intangible drilling costs in the year incurred; repeal of the percentage depletion deduction for crude oil and gas properties; repeal of the domestic manufacturing tax deduction for oil and gas companies; increase in the geological and geophysical amortization period for independent producers; and implementation of a fee on non-producing leases located on federal lands. Should some or all of these provisions become law our taxes could increase, potentially significantly, after net operating losses are exhausted, which would have a negative impact on our net income and cash flows. This could also reduce our drilling activities. We do not know the ultimate impact these proposed changes may have on our business.

We depend on our key management personnel and technical experts and the loss any of these individuals could adversely affect our business.

If we lose the services of our key management personnel, technical experts or are unable to attract additional qualified personnel, our business, financial condition, results of operations, development efforts and ability to grow could suffer. We have assembled a team of engineers, geologists and geophysicists who have considerable experience in applying advanced drilling and completion techniques to explore for and to develop crude oil and natural gas. We depend upon the knowledge, skill and experience of these experts to assist us in improving the performance and reducing the risks associated with our participation in crude oil and natural gas exploration and development projects. In addition, the success of our business depends, to a significant extent, upon the abilities and continued efforts of our management, particularly Ben M. Brigham, our Chief Executive Officer, President and Chairman of the Board. We have an employment agreement with Mr. Brigham, but do not have an employment agreement with any of our other employees.

Lower crude oil and natural gas prices may cause us to record ceiling limitation writedowns, which would reduce our stockholders' equity.

We use the full cost method of accounting for our crude oil and natural gas investments. Accordingly, we capitalize the cost to acquire, explore for and develop crude oil and natural gas properties. Under full cost accounting rules, the net capitalized cost of crude oil and natural gas properties may not exceed a "ceiling limit" that is based upon the present value of estimated future net revenues from proved reserves, discounted at 10%, plus the lower of the cost or fair market value of unproved properties. If net capitalized costs of crude oil and natural gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling limitation writedown." The risk that we will experience a ceiling limitation writedown increases when crude oil and natural gas prices are depressed or if we have substantial downward revisions in estimated proved reserves. Based on crude oil and natural gas prices in effect on March 31, 2009 ($3.63 per MMBtu for Henry Hub gas and $49.65 per barrel for West Texas Intermediate crude oil, adjusted for differentials), the unamortized cost of our crude oil and natural gas properties exceeded the ceiling limit. As such, we recorded a $114.8 million ($71.9 million after tax) impairment to our crude oil and gas properties at March 31, 2009. Based on crude oil and natural gas prices in effect on December 31, 2008 ($5.71 per MMBtu for Henry Hub gas and $44.60 per barrel for West Texas Intermediate crude oil, adjusted for differentials), the unamortized cost of our crude oil and natural gas properties exceeded the ceiling limit. As such, we recorded a $237.2 million ($148.6 million after tax) impairment to our crude oil and natural gas properties at December 31, 2008. We may be required to recognize additional pre-tax non-cash impairment charges in the future reporting periods if market prices for crude oil or natural gas decline.

We may have difficulty financing our planned capital expenditures, which could adversely affect our business.

We make and hope to continue to make substantial capital expenditures in our exploration and development projects. Without additional capital resources, our drilling and other activities may be limited and our business, financial condition and results of operations may suffer. We may not be able to secure additional financing on reasonable terms or at all, and financing may not continue to be available to us under our existing or new financing arrangements. If additional capital resources are unavailable, we may curtail our drilling, development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis. Any such curtailment or sale could have a material adverse effect on our business, financial condition and results of operation.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage or the leases are extended.

As of December 31, 2010, we had mineral leases on approximately 364,309 net acres in the Williston Basin which we believe are prospective for the Bakken and/or Three Forks. A significant portion of the acreage is not currently held by production. Unless production in paying quantities is established on units containing these leases during their primary terms or we obtain extensions of the leases, these leases will expire. If our leases expire, we will lose our right to develop the related properties.

Our drilling plans for these areas are subject to change based upon various factors, including factors that are beyond our control, including drilling results, crude oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals.

Our exploration, development and drilling efforts and the operation of our wells may not be profitable or achieve our targeted returns.

We require significant amounts of undeveloped leasehold acreage in order to further our development efforts. Exploration, development, drilling and production activities are subject to many risks, including the risk that commercially productive reservoirs will not be discovered. We invest in property, including undeveloped leasehold acreage, which we believe will result in projects that will add value over time. However, we cannot guarantee that all of our prospects will result in viable projects or that we will not abandon our initial investments. Additionally, we cannot guarantee that the leasehold acreage we acquire will be profitably developed, that new wells drilled by us in provinces that we pursue will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for crude oil and natural gas may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting operating and other costs. Wells that are profitable may not achieve our targeted rate of return. Our ability to achieve our target results is dependent upon the current and future market prices for crude oil and natural gas, costs associated with producing crude oil and natural gas and our ability to add reserves at an acceptable cost. Additionally, we rely to some extent on 3-D seismic data and other advanced technologies in identifying leasehold acreage prospects and in conducting our exploration activities. These technologies we use do not allow us to know conclusively prior to the acquisition of leasehold acreage or the drilling of a well whether crude oil or natural gas is present or may be produced economically.

In addition, we may not be successful in implementing our business strategy of controlling and reducing our drilling and production costs in order to improve our overall return. The cost of drilling, completing and operating a well is often uncertain and cost factors can adversely affect the economics of a project. We cannot predict the cost of drilling, and we may be forced to limit, delay or cancel drilling operations as a result of a variety of factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs, fracture stimulation crews or other types of equipment necessary in the oil and gas industry.

Exploratory drilling is a speculative activity that may not result in commercially productive reserves and may require expenditures in excess of budgeted amounts.

Our future rate of growth somewhat depends on the success of our exploratory drilling program. Exploratory drilling involves a higher degree of risk that we will not encounter commercially productive crude oil or natural gas reservoirs than developmental drilling. We may not be successful in our future drilling activities because, even with the use of advanced horizontal drilling and completion techniques, 3-D seismic and other advanced technologies, exploratory drilling is a speculative activity.

Although our crude oil and natural gas reserve data is independently estimated, these estimates may still prove to be inaccurate.

Our proved reserve estimates are prepared each year by Cawley, Gillespie & Associates, Inc. ("CGA"), a registered independent petroleum consulting firm. In conducting its evaluation, the engineers and geologists of CGA evaluate our properties and independently develop proved reserve estimates. There are numerous uncertainties and risks that are inherent in estimating quantities of crude oil and natural gas reserves and projecting future rates of production and timing of development expenditures as many factors are beyond our control. There are many factors and assumptions incorporated into our reserve estimates including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future crude oil and gas prices and quality and location differentials; and
- future development and operating costs.

Although we believe the CGA reserve estimates are reasonable based on the information available to them at the time they prepare their estimates, our actual results could vary materially from these estimated quantities of proved crude oil and natural gas reserves (in the aggregate and for a particular location), production, revenues, taxes and development and operating expenditures. In addition, these estimates of proved reserves may be subject to downward or upward revision based upon production history, results of future exploration and development, prevailing crude oil and natural gas prices, operating and development costs and other factors.

Finally, recovery of proved undeveloped reserves generally requires significant capital expenditures and successful drilling operations. At December 31, 2010, approximately 65% of our estimated proved reserves were classified as undeveloped. At December 31, 2010, we estimated that it would require additional capital expenditures of approximately $738.9 million to develop our proved undeveloped reserves. Our reserve estimates assume that we can and will make these expenditures and conduct these operations successfully, which may not occur.

We need to replace our reserves at a faster rate than companies whose reserves have longer production periods. Our failure to replace our reserves would result in decreasing reserves and production over time.

In general, production from crude oil and natural gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Except to the extent we conduct successful exploration and development activities or acquire properties containing proved reserves, or both, our proved reserves and production will decline as reserves are produced.

We may not be able to find, develop or acquire additional reserves to replace our current and future production. Accordingly, our future crude oil and natural gas reserves and production and therefore our future cash flow and income, are dependent upon our success in economically finding or acquiring new reserves and efficiently developing our existing reserves.

Our reserves in the Gulf Coast have high initial production rates followed by steep declines in production, resulting in a reserve life for wells in this area that is shorter than the industry average. This production volatility has impacted and, in the future, may continue to impact our quarterly and annual production levels.

We generally must locate and develop or acquire new crude oil and natural gas reserves to replace those being depleted by production. Without successful drilling and exploration or acquisition activities, our reserves and revenues will decline rapidly. We may not be successful in extending the reserve life of our properties generally and our Gulf Coast properties in particular. Our current strategy includes increasing our reserve base through drilling activities in our Williston Basin province and in our other core areas, which have historically had longer-lived reserves. Our existing and future exploration and development projects may not result in significant additional reserves and we may not be able to drill productive wells at economically viable costs.

Our future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of crude oil and natural gas and our success in finding and producing new reserves. If our revenues were to decrease as a result of lower crude oil and natural gas prices, decreased production or otherwise, and our access to capital were limited, we would have a reduced ability to replace our reserves or to maintain production at current levels, potentially resulting in a decrease in production and revenue over time.

We may not drill all of our potential drilling locations and drilling locations that we decide to drill may not yield crude oil or natural gas in commercially viable quantities or quantities sufficient to meet our targeted rate of return.

Our drilling locations are in various stages of evaluation, ranging from locations that are ready to be drilled to potential locations that will require substantial additional evaluation and interpretation. Most of our potential drilling locations have not been attributed proved undeveloped reserves. A decision to drill any specific well on our large inventory of potential well locations may not be made for many years, if at all. If a decision is made to drill, there is no way to conclusively predict in advance of drilling and testing whether any particular drilling location will yield crude oil or natural gas in sufficient quantities to recover our drilling or completion costs or to be economically viable. Our use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether crude oil and natural gas will be present or, if present, whether crude oil and natural gas will be present in commercial quantities. The analysis that we perform using data from other wells, more fully explored prospects and/or producing fields may not be useful in predicting the characteristics and potential reserves associated with our drilling locations. As a result, we may not find commercially viable quantities of crude oil and natural gas and, therefore, we may not achieve a targeted rate of return or have a positive return on investment.

The marketability of our crude oil and natural gas production depends on services and facilities that we typically do not own or control. The failure or inaccessibility of any such services or facilities could affect market based prices or result in a curtailment of production and revenues.

The marketability of our crude oil and natural gas production depends in part upon the availability of, proximity to and capacity of crude oil and natural gas gathering and transportation systems, crude oil and natural gas pipelines and processing facilities. We generally deliver crude oil at our leases under short-term contracts. Counterparties to our short-term contracts rely on access to regional transportation systems and pipelines. If transportation systems or pipeline capacity is constrained, we would be required to find alternative transportation modes, which would impact our market based price, or temporarily curtail production. We generally deliver natural gas through gas gathering systems and gas pipelines that we do not own under interruptible or short term transportation agreements. Under the interruptible transportation agreements, the transportation of our natural gas may be interrupted due to capacity constraints on the applicable system, for maintenance or repair of the system, or for other reasons as dictated by the particular agreements. If any of the pipelines or other facilities become unavailable, we would be required to find a suitable alternative to transport and process the natural gas, which could increase our costs and reduce the revenues we might obtain from the sale of the natural gas. For example, in 2008, Hurricanes Gustav and Ike disrupted our Gulf Coast operations forcing us to temporarily curtail production and delayed bringing new wells on line. Hurricane Ike forced us to curtail approximately 1.0 MMcfe per day of production during the third quarter 2008. Furthermore, both Hurricanes Gustav and Ike delayed our completion operations on our Southern Louisiana wells reducing third quarter 2008 production by an estimated 1.8 MMcfe per day.

We are subject to various operating and other casualty risks that could result in liability exposure or the loss of production and revenues.

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

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

Any of these hazards and risks can result in the loss of hydrocarbons, environmental pollution, personal injury claims and other damage to our properties and the property of others.

We may not have enough insurance to cover all of the risks we face, which could result in significant financial exposure.

We maintain insurance coverage against some, but not all, potential losses in order to protect against the risks we face. We may elect not to carry insurance if our management believes that the cost of insurance is excessive relative to the risks presented. If an event occurs that is not covered, or not fully covered, by insurance, it could harm our financial condition, results of operations and cash flows. In addition, we cannot fully insure against pollution and environmental risks.

We cannot control activities on properties we do not operate. Failure to fund capital expenditure requirements may result in reduction or forfeiture of our interests in some of our non-operated projects.

We do not operate some of the properties in which we have an interest and we have limited ability to exercise influence over operations for these properties or their associated costs. As of December 31, 2010, approximately 19% of our crude oil and natural gas proved reserves were operated by other companies. Our dependence on other operators and other working interest owners for these projects and our limited ability to influence operations and associated costs could materially adversely affect the realization of our targeted return on capital in drilling or acquisition activities and our targeted production growth rate. The success and timing of drilling, development and exploitation activities on properties operated by others depend on a number of factors that are beyond our control, including the operator's expertise and financial resources, approval of other participants for drilling wells and utilization of technology.

When we are not the majority owner or operator of a particular crude oil or natural gas project, we may have no control over the timing or amount of capital expenditures associated with such project. If we are not willing or able to fund our capital expenditures relating to such projects when required by the majority owner or operator, our interests in these projects may be reduced or forfeited.

Our future operating results may fluctuate and significant declines in them would limit our ability to invest in projects.

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

- industry conditions;
- prices of crude oil and natural gas;
- rates of drilling success;

- capital availability;
- rates of production from completed wells; and
- the timing and amount of capital expenditures.

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

We face significant competition and many of our competitors have resources in excess of our available resources.

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

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

Many of our competitors have financial and other resources substantially in excess of those available to us. This highly competitive environment could harm our business.

We are subject to various governmental regulations and environmental risks that may cause us to incur substantial costs.

From time to time, in varying degrees, political developments and federal and state laws and regulations affect our operations. In particular, price controls, taxes and other laws relating to the oil and natural gas industry, changes in these laws and changes in administrative regulations have affected and in the future could affect crude oil and natural gas production, operations and economics. We cannot predict how agencies or courts will interpret existing laws and regulations or the effect of these adoptions and interpretations may have on our business or financial condition.

Our business is subject to laws and regulations promulgated by federal, state and local authorities, including but not limited to the United States Congress, FERC, the EPA, the BLM, the TRRC, the TCEQ, the OCC, the LDNR, the NDIC and the MBOGC relating to the exploration for, and the development, production and marketing of, crude oil and natural gas, as well as safety matters. Legal requirements are frequently changed and subject to interpretation and we are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. We may be required to make significant expenditures to comply with governmental laws and regulations. The discharge of crude oil, natural gas or other pollutants into the air, soil or water may give rise to significant liabilities on our part to the government and third parties and may require us to incur substantial costs of remediation.

Our operations are subject to complex federal, state and local environmental laws and regulations, including the CERCLA, the Resource Conservation and Recovery Act, the OPA, and the Clean Water Act. Environmental laws and regulations change frequently, and the implementation of new, or the modification of existing, laws or regulations could harm us. For example, in the 111th Congress, companion bills were introduced in the United States Senate and House of Representatives. These bills would have repealed the exemption for hydraulic fracturing from the federal Safe Drinking Water Act, which would have had the effect of allowing the EPA to promulgate regulations requiring permits and imposing new restrictions on hydraulic fracturing under the federal Safe Drinking Water Act. This could, in turn, require state regulatory agencies in states with programs delegated under the Safe Drinking Water Act to impose additional requirements on hydraulic fracturing operations. In addition, the bills would have required persons using hydraulic fracturing, such as us, to disclose the chemical constituents, but not the proprietary formulas, of their fracturing fluids to a regulatory agency, which would make the information public via the internet, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. If legislation similar to that introduced in the 111th Congress becomes law, it could establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business. Compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the potential impact on our business that may arise if the federal or state legislation is enacted into law. In addition, in March 2010, the EPA announced its intention to conduct a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health. Preliminary results of the study are expected in 2012. Thus, even if the pending legislation is not adopted, the EPA study, depending on its results, could spur further initiatives to regulate hydraulic fracturing under the Safe Drinking Water Act.

Derivatives regulation included in current financial reform legislation could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices.

Last year, the United States Congress recently adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act, which contains comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as the Company, that participate in that market. The new legislation was signed into law by the President on July 21, 2010 and requires the CFTC and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation. The financial reform legislation contains significant derivatives regulation, including provisions requiring certain transactions to be cleared on exchanges and containing a requirement to post cash collateral (commonly referred to as "margin") for such transactions as well as certain clearing and trade-execution requirements in connection with our derivative activities. The Act provides for a potential exception from these clearing and cash collateral requirements for commercial end-users and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and to the parties to those transactions. However, we do not know the definitions that the CFTC will actually promulgate nor how these definitions will apply to us. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

Depending on the rules and definitions adopted by the CFTC, we could be required to post cash collateral with our dealer counterparties for our commodities hedging transactions. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post cash collateral which could adversely affect our available liquidity, thereby reducing our ability to use cash for investment or other corporate purposes, or could require us to increase our level of debt), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of crude oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to crude oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. In addition, a requirement for our counterparties to post cash collateral would likely result in additional costs being passed on to us, thereby decreasing the effectiveness of our hedges and our profitability. Any of these consequences could have a material, adverse effect on us, our financial condition, and our results of operations.

The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the crude oil and natural gas we produce.

In the 111th Congress, two climate change bills were introduced that would have established a "cap and trade" system for restricting greenhouse gas emissions. Under such system, certain sources of greenhouse gas emissions would be required to obtain greenhouse gas emission "allowances" corresponding to their annual emissions of greenhouse gases. The number of emission allowances issued each year would decline as necessary to meet overall emission reduction goals. As the number of greenhouse gas emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The current or a future Congress could enact similar legislation. In addition to the possible climate legislation, the EPA has issued greenhouse gas monitoring and reporting regulations that went into effect January 1, 2010, and require reporting by regulated facilities by March 2011 and annually thereafter. On November 8, 2010, the EPA finalized a rule that sets forth reporting requirements for the petroleum and natural gas industry and requires persons that hold state drilling permits and that emit 25,000 metric tons or more of carbon dioxide equivalent per year to annually report carbon dioxide, methane and nitrous oxide emissions from certain sources. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The EPA has proposed regulations that would require permits for and reductions in greenhouse gas emissions for certain facilities, and may issue final rules in 2011. Any laws or regulations that may be adopted to restrict or reduce emissions of GHGs could require us to incur increased operating costs, and could have an adverse effect on demand for the crude oil and natural gas we produce, depending on the applicability to company operations and the refining, processing, and use of crude oil and gas.

Our level of indebtedness may adversely affect our cash available for operations, which would limit our growth, our ability to make interest and principal payments on our indebtedness as they become due and our flexibility to respond to market changes.

As of February 25, 2011, we had $300 million in outstanding indebtedness, as well as $325 million of borrowing capacity under our Senior Credit Facility. Our level of indebtedness will have several important effects on our operations, including:

- we will dedicate a portion of our cash flow from operations to the payment of interest on our indebtedness and to the payment of our other current obligations and will not have these cash flows available for other purposes;

- our debt agreements limit our ability to borrow additional funds or dispose of assets and may affect our flexibility in planning for, and reacting to, changes in business conditions;

- our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate purposes or other purposes may be impaired;

- we may be more vulnerable to economic downturns and our ability to withstand sustained declines in oil and natural gas prices may be impaired;

- since outstanding balances under our Senior Credit Facility are subject to variable interest rates, we are vulnerable to increases in interest rates;

- our flexibility in planning for or reacting to changes in market conditions may be limited; and

- it may place us at a competitive disadvantage compared to our competitors that have less debt.

Our ability to meet our debt obligations and reduce our level of indebtedness depends on future performance. General economic conditions, oil and natural gas prices and financial, business and other factors will affect our operations and our future performance. Many of these factors are beyond our control and we may not be able to generate sufficient cash flow to pay the interest on our debt. In addition, borrowings and equity financing may not be available to pay or refinance such debt.

The indenture governing the Senior Notes and the documents governing our Senior Credit Facility impose significant operating and financial restrictions, which may prevent us from capitalizing on business opportunities and taking some actions.

The indenture governing the notes and the documents governing our Senior Credit Facility contain customary restrictions on our activities, including covenants that restrict our and our subsidiaries' ability to:

- incur additional debt;
- pay dividends on, redeem or repurchase stock;
- create liens;
- make specified types of investments;
- apply net proceeds from certain asset sales;
- engage in transactions with our affiliates;
- engage in sale and leaseback transactions;
- merge or consolidate;
- restrict dividends or other payments from subsidiaries;
- sell equity interests of subsidiaries; and
- sell, assign, transfer, lease, convey or dispose of assets.

The indenture governing our Senior Notes contains certain incurrence-based covenants that will limit our ability to incur debt and engage in other transactions. One of these covenants incorporates the net present value of our proved reserves calculated based on SEC rules. Our ability to increase our borrowings in 2011 will depend, in part, on prices for oil and natural gas utilized in our year-end 2010 reserve report. Our Senior Credit Facility also requires us to meet a minimum current ratio and a net leverage ratio. We may not be able to maintain or comply with these ratios, and if we fail to be in compliance with these tests, we will not be able to borrow funds under our Senior Credit Facility, which would make it difficult for us to operate our business.

The restrictions in the indenture governing the Senior Notes and the documents governing our Senior Credit Facility may prevent us from taking actions that we believe would be in the best interest of our business, and may make it difficult for us to successfully execute our business strategy or effectively compete with companies that are not similarly restricted. We may also incur future debt obligations that might subject us to additional restrictive covenants that could affect our financial and operational flexibility. We cannot assure you that we will be granted waivers or amendments to these agreements if for any reason we are unable to comply with these agreements, or that we will be able to refinance our debt on terms acceptable to us, or at all.

The breach of any of these covenants and restrictions could result in a default under the indenture governing the Senior Notes or under the documents governing our Senior Credit Facility. An event of default under our debt agreements would permit some of our lenders to declare all amounts borrowed from them to be due and payable. If we are unable to repay such indebtedness, lenders having secured obligations, such as the lenders under our Senior Credit Facility, could proceed against the collateral securing the debt. Because the indenture governing the notes and the documents governing our Senior Credit Facility have customary cross-default provisions, if the indebtedness under the notes or under our Senior Credit Facility or any of our other facilities is accelerated, we may be unable to repay or finance the amounts due.

Availability under our Senior Credit Facility is based on a borrowing base which is subject to redetermination by our lenders. If our borrowing base is reduced, we may be required to repay amounts outstanding under our Senior Credit Facility.

Under the terms of our Senior Credit Facility, our borrowing base is subject to semi-annual redetermination by our lenders based on their valuation of our proved reserves and their internal criteria. In addition to such semi-annual determinations, our lenders may request one additional borrowing base redetermination during any 12-month period. Our borrowing base is also subject to reduction if we monetize certain of our hedging transactions. In the event the amount outstanding under our Senior Credit Facility at any time exceeds the borrowing base at such time, we may be required to repay a portion of our outstanding borrowings over a period no longer than six months. If we do not have sufficient funds on hand for repayment, we may be required to seek a waiver or amendment from our lenders, refinance our Senior Credit Facility, sell assets or sell additional shares of common stock. We may not be able obtain such financing or complete such transactions on terms acceptable to us, or at all. Failure to make the required repayment could result in a default under our Senior Credit Facility, which could adversely affect our business, financial condition and results or operations. Our borrowing base is currently set at $325 million until the next borrowing base redetermination provided for in the Senior Credit Facility, which is scheduled for November 2011. We have no borrowings drawn on our Senior Credit Facility.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Borrowings under our Senior Credit Facility bear interest at variable rates and expose us to interest rate risk. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase although the amount borrowed remained the same, and our net income and cash available for servicing our indebtedness would decrease.

We may incur additional indebtedness. This could further exacerbate the risks associated with our substantial leverage.

We may incur substantial additional indebtedness in the future. The indenture that will govern the notes and documents governing our Senior Credit Facility contain restrictions on our ability to incur indebtedness. These restrictions, however, are subject to a number of qualifications and exceptions, and under certain circumstances we could incur substantial additional indebtedness in compliance with these restrictions. Moreover, these restrictions do not prevent us from incurring obligations that do not constitute "Indebtedness" or "Debt" under the indenture and the Senior Credit Facility, respectively. If we incur indebtedness above our current debt levels, the related risks that we now face could intensify and we may not be able to meet all our debt obligations. Failure to meet these obligations could result in a default under our debt documents, which could adversely affect our business, financial condition and results of operations.

To service our indebtedness we will require a significant amount of cash. Our ability to generate cash depends on many factors beyond our control. Failure to generate sufficient cash to service our indebtedness could adversely affect our business, financial condition and results of operations.

Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be subject to general economic, financial, competitive, legislative, regulatory and other factors that are beyond our control. We cannot assure you that our business will generate sufficient cash flow from operations or that future borrowings will be available to us under our Senior Credit Facility or otherwise in an amount sufficient to enable us to pay our indebtedness or to fund our other liquidity needs.

If we are unable to meet our debt service obligations, we may be required to seek a waiver or amendment from our debt holders, refinance such debt obligations or sell assets or additional shares of common stock. We may not be able obtain such financing or complete such transactions on terms acceptable to us, or at all. Failure to meet our debt obligations could result in a default under the agreements governing our indebtedness. An event of default under our debt agreements would permit some of our lenders to declare all amounts borrowed from them to be due and payable. If we are unable to repay such indebtedness, lenders having secured obligations, such as the lenders under our Senior Credit Facility, could proceed against the collateral securing the debt. Because the indenture governing the notes and the documents governing our Senior Credit Facility have customary cross-default provisions, if the indebtedness under the notes or under our Senior Credit Facility or any of our other facilities is accelerated, we may be unable to repay or finance the amounts due.

The market price of our stock is volatile.

The trading price of our common stock and the price at which we may sell securities in the future are subject to large fluctuations in response to any of the following:

- limited trading volume in our stock;
- changes in government regulations;
- quarterly variations in operating results;
- our involvement in litigation;
- general market conditions;
- the prices of crude oil and natural gas;
- announcements by us and our competitors;
- our liquidity;
- our ability to raise additional funds; and
- other events.

Our stock price may decline when our financial results decline or when events occur that are adverse to us or our industry.

You can expect the market price of our common stock to decline when our financial results decline or otherwise fail to meet the expectations of the financial community or the investing public or at any other time when events actually or potentially adverse to us or the oil and natural gas industry occur. Our common stock price may decline to a price below the price you paid to purchase your shares of common stock.

We are prohibited from paying dividends on our common stock.

We will retain all future earnings and other cash resources for the future operation and development of our business. The documents governing our Senior Credit Facility and the indenture governing our Senior Notes prohibit the payment of dividends. Accordingly, we do not intend to declare or pay any cash dividends on our common stock in the foreseeable future.

Certain anti-takeover provisions may adversely affect your rights as a stockholder.

Our certificate of incorporation authorizes our Board of Directors to issue up to 10 million shares of preferred stock without stockholder approval and to set the rights, preferences and other designations, including voting rights, of those shares as the Board of Directors may determine. In addition, the documents governing our Senior Credit Facility and our indenture governing our Senior Notes contain terms restricting our ability to enter into change of control transactions, including requirements to redeem or repay upon a change in control, the amounts borrowed under our Senior Credit Facility and our Senior Notes. These provisions, alone or in combination with the other matters described in the preceding paragraph, may discourage transactions involving actual or potential changes in our control, including transactions that otherwise could involve payment of a premium over prevailing market prices to holders of our common stock. We are also subject to provisions of the Delaware General Corporation Law that may make some business combinations more difficult.

Forward-Looking Statements

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

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

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

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

You should be aware that our actual results could differ materially from those contained in the forward-looking statements. You should consider carefully the statements in this "Item 1A. Risk Factors" and other sections of this report, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

Historically, our exploration and development activities have been focused in our Onshore Gulf Coast, the Anadarko Basin and West Texas provinces. However, in late 2007, the majority of our capital expenditures shifted from our historically active areas to the Williston Basin, where we are primarily targeting the Bakken and Three Forks producing horizons. As of December 31, 2010, we had approximately 600,601 gross and 364,309 net leasehold acres in the Williston Basin. In 2010, we drilled and completed or were in the process of completing 151 gross (38.9 net) wells on our Williston Basin acreage investing a total of $404.8 million on drilling, land and support infrastructure, before the impact of asset sale proceeds. At year-end 2010, we were also drilling 21 gross (2.7 net) wells. Since entering the Williston Basin in late 2005, we have invested in excess of $625 million on drilling, land, seismic and support infrastructure.

In 2010, we spent a total of approximately $426.8 million on drilling, land and support infrastructure in our operating areas. During 2011, we plan to spend approximately $582.1 million on drilling 68.1 net wells as well as to complete wells that were in progress at December 31, 2010. We currently expect to spend approximately $27.4 million on land. Finally, we expect to spend $83.2 million on support infrastructure to continue to expand gathering lines and add water disposal wells. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Capital Commitments — Capital Expenditures." The following is a summary of our properties by major province as of December 31, 2010, unless otherwise noted.

	Williston Basin	Onshore Gulf Coast	Anadarko Basin	West Texas and Other	Total
Capital expenditures for drilling, land and support infrastructure in 2010 (in millions) (a)	$ 404.8	$ 16.4	$ 0.7	$ 4.9	$ 426.8
Proved Reserves at December 31, 2010					
Pre-tax PV10% (in millions) (b)	$ 939.4	$ 127.7	$ 22.1	$ 19.5	$1,108.7
Crude oil (MMBbls)	49.5	1.6	0.2	0.9	52.2
Natural gas (Bcf)	36.3	36.2	14.5	0.8	87.8
Oil equivalents (MMBoe) (c)	55.5	7.6	2.6	1.1	66.8
% Oil	89%	21%	7%	87%	78%
Average daily production volumes (MBoe) (d)	6,146	1,394	558	169	8,267
Average daily sales volumes (MBoe)(d)	6,064	1,394	558	169	8,185
Productive wells at December 31, 2010					
Gross	237	85	89	31	442
Net	61.0	44.5	23.6	7.6	136.7

(a) Onshore Gulf Coast, Anadarko Basin and West Texas & Other capital expenditures are before the impact of proceeds from the sale of assets.

(b) The standardized measure for our proved reserves at December 31, 2010, was $866.1 million. See "-Reconciliation of Standardized Measure to Pre-tax PV10%" for a definition of pre-tax PV10% and a reconciliation of our standardized measure to our pre-tax PV10% value. The prices used to calculate this measure were $79.43 per barrel of oil and $4.376 per MMbtu of natural gas. These prices represent the average prices per barrel of oil and per MMbtu of natural gas at the beginning of each month in the 12-month period prior to the end of the reporting period. These prices were adjusted to reflect applicable transportation and quality differentials on a well-by-well basis to arrive at realized sales prices used to estimate our reserves at this date.

(c) Boe is defined as one barrel of oil equivalent determined using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids.

(d) Average daily production volumes calculated based on 360 day year. Average daily production volumes include approximately 29,654 barrels of oil produced during 2010 and recorded as inventory at year-end 2010. Total oil inventory at year-end 2010 and 2009 was 46,129 and 16,475 barrels of crude oil, respectively. Total crude oil inventory at year-end 2008 was not material. Adjusting production volumes for amounts included in inventory would result in average daily sales volumes in 2010 and 2009 of 8,185 and 4,988 barrels of oil per day.

Williston Basin Province

In late 2005, we began accumulating acreage in the Williston Basin located in North Dakota and Montana. During 2010, we invested approximately $404.8 million in drilling, land and support infrastructure. During 2010, we drilled and completed or were in the process of completing 151 gross wells (38.9 net) in the Williston Basin. At year-end 2010, there were 21 gross wells (2.7 net) drilling.

Overview of Williston Basin

The Williston Basin is spread across North Dakota, Montana and parts of southern Canada with the United States portion of the basin encompassing approximately 125,000 square miles. The basin produces oil and gas from numerous horizons including, but not limited to, the Bakken and Three Forks, which are currently our primary horizontal objectives.

The Bakken is an unconventional oil shale play at depths of approximately 10,000 to 10,500 feet that is primarily exploited via advanced drilling and completion techniques. The Bakken interval is comprised, from top to bottom, of the Upper Bakken Shale, Middle Bakken and Lower Bakken Shale. The Upper and Lower Bakken Shales are lithologically similar world class source rocks with total organic content of approximately 11%. Both the Upper and Lower Bakken Shales serve as the source rock for the Middle Bakken, which is a dolomite and is the zone targeted for our horizontal well bores. The dolomitic nature of the Middle Bakken allows us to propagate fractures during our multi-stage fracture stimulations and we retain long-term conductivity to the well bore via the use of ceramic proppants. During 2010, industry activity greatly increased west of the Nesson Anticline in Williams and McKenzie Counties, North Dakota. Industry activity is also increasing westward into Eastern Montana in both Richland and Roosevelt Counties.

The upper Three Forks is an unconventional carbonate play that lies just below the Bakken and is charged by the Lower Bakken Shale. Similar to the Middle Bakken, the upper Three Forks is primarily exploited using advanced drilling and completion techniques, which include multi-stage fracture stimulations. Drilling in the upper Three Forks began in mid-2008 and a number of operators, including us, are targeting this formation as a parallel objective to the Bakken formation. Drilling in this formation is early, but initial results appear to indicate that the upper Three Forks is a separate reservoir from the Bakken, which increases our exposure to crude oil reserves in the basin.

Overview of Williston Basin Acreage Position

Our acreage position in the Williston Basin is comprised of approximately 364,309 net acres. Approximately 95,011 net acres is east of the Nesson Anticline in Mountrail County, North Dakota and adjoining counties to the north, south and east. Acreage east of the Nesson Anticline includes approximately 5,319 net acres in our Parshall / Austin / Sanish project area in Mountrail County where drilling activities are typically operated by others and we therefore participate in wells in a non-operated role. Acreage east of the Nesson Anticline also incorporates approximately 34,960 net acres in our Ross Project area in Mountrail County where we both operate and participate in non-operated Bakken and Three Forks wells.

Approximately 155,065 net acres are west of the Nesson Anticline in Williams and McKenzie Counties, North Dakota in our Rough Rider project area. Acreage in our Rough Rider project area is subject to the Drilling Participation Agreement outlined below. Typically, because of our higher working interests in spacing units, we operate wells in our Rough Rider area but to a lesser degree will also participate in wells in a non-operated role.

Our remaining 114,233 net acres are located in eastern Montana in Roosevelt, Richland and Sheridan Counties in our Eastern Montana project area. Industry activity in Montana has been increasing with a number of operators drilling and permitting wells in and around our acreage.

Overview of Rough Rider Drilling Participation Agreement

In late August 2009, we entered into a drilling participation agreement in our Rough Rider project area in order to accelerate operations and address near term state lease expirations. The initial 15 wells under the agreement have been drilled or were in the process of being drilled at year-end. In each of the initial six wells, we have retained 35% of our original working interest and will back in for 35% of our counterparty's interest in the combined six well group after combined payout (defined as the point in time when the cumulative net receipts from the initial wells equals or exceeds all expenditures for such wells). Our counterparty exercised its option to participate in the additional nine wells and we elected to retain our maximum interest of 50% of our original working interest in the additional nine wells. Further, we will have the option to keep up to 64% of our original working interest in all subsequent in fill development wells in all 15 drilling units.

2010 Williston Basin Drilling and Completion Activity

WELL NAME	County	OBJECTIVE	~WI	FRAC STAGES	IP (Boe/d)	30 DAY Average (Boe/d)**
Arvid Anderson 14-11 #1H ..	Mountrail	Bakken	68%	38	3,191	1,330
Roger Sorenson 8-5 #1H	Mountrail	Bakken	54%	38	2,658	1,120
Heen 26-35 #1H....................	Williams	Bakken	76%	38	3,791	1,379
Brakken 30-31 #1H	Williams	Bakken	56%	30	3,573	1,277
Lippert 1-12 #1H	Williams	Bakken	66%	31	2,214	942
Brad Olson 9-16 #2H............	Williams	Bakken	56%*	32	2,717	773
Smith Farms 23-14 #1H	Williams	Bakken	82%	32	2,417	1,041
Abelmann 23-14 #1H	McKenzie	Bakken	53%	33	4,169	1,407
Clifford Bakke 26-35 #1H....	Mountrail	Bakken	43%	38	5,061	2,328
Boots 13-24 #1H..................	Williams	Bakken	74%	31	1,946	662
Larsen 3-10 #1H	Williams	Bakken	72%	31	3,090	1,034
Domaskin 30-31 #1H...........	Mountrail	Bakken	65%	38	4,675	1,882
State 36-1 #2H......................	Williams	Three Forks	30%*	31	2,356	874
Sukut 28-33 #1H...................	Williams	Bakken	42%*	32	1,959	801
Abe Owan 21-16 #1H...........	Williams	Bakken	57%	37	2,213	900
Weisz 11-14 #1H	Williams	Bakken	52%	37	2,278	1,014
Wright 4-33 #1H...................	Mountrail	Bakken	88%	38	3,660	1,322
Michael Owan 26-35 #1H	Williams	Bakken	87%	33	2,931	889
Sedlacek Trust 33-4 #1H......	McKenzie	Bakken	48%*	30	2,695	826
Rogney 17-8 #1H	Roosevelt	Bakken	100%	30	909	355
Ross Alger 6-7 #1H	Mountrail	Bakken	47%	32	3,070	1,465
Owan 29-32 #1H	Williams	Bakken	78%	31	2,302	868
Abe 30-31 #1H	Williams	Bakken	97%	31	1,847	731
Jack Cvancara 19-18 #1H.....	Mountrail	Bakken	83%	36	5,035	1,800
Tjelde 29-32 #1H..................	McKenzie	Bakken	77%	30	3,171	931
Abelmann State 21-16 #1H ..	McKenzie	Bakken	64%	31	3,301	1,044
Mortenson 5-32 #1H............	Williams	Bakken	77%	23	2,314	584
Arnson 13-24 #1H	Williams	Bakken	93%	30	1,339	480
Sorenson 29-32 #1H	Mountrail	Bakken	95%	27	5,133	1,909
Jack Erickson 6-31 #1H........	Williams	Bakken	21%*	30	2,652	833
Jerome Anderson 15-10 #1H..........................	Mountrail	Bakken	50%	30	3,115	1,146
Papineau Trust 17-20 #1H....	Williams	Bakken	43%*	29	3,042	971
Kalil 25-36 #1H....................	Williams	Bakken	38%*	30	1,586	650
Liffrig 29-20 #1H	Mountrail	Three Forks	72%	29	2,477	1,082
Owan-Nehring 27-34...........	Williams	Bakken	49%	30	2,513	1,089
Jackson 35-34 #1H	Williams	Bakken	62%	30	3,540	907
State 36-1 #1H......................	Williams	Bakken	16%*	30	3,807	1,516
				Averages	**2,939**	**1,085**

* Rough Rider drilling participation agreement wells where our working interest is anticipated to increase upon payout.

** Excludes any days well was down for remediation.

2011 Williston Basin Drilling and Completion Activity / 2011 Capital Budget

WELL NAME	County	OBJECTIVE	~WI	FRAC STAGES	IP (Boe/d)	30 DAY Average (Boe/d)**
Knoshaug 14-11 #1H.........	Williams	Bakken	50%	36	4,443	NA
Gibbins 1-12 #1H.............	McKenzie	Bakken	55%	33	2,582	NA
Swindle 16-9 #1H.............	Roosevelt	Bakken	52%	19	1,065	NA
Lloyd 34-3 #1H	McKenzie	Bakken	29%*	31	4,030	1,456
Bratcher 10-3 #1H	McKenzie	Bakken	91%	30	3,667	1,129
M. Macklin 15-22 #1H......	Williams	Bakken	89%	38	2,534	1,062
M. Olson 20-29 #1H..........	Williams	Bakken	91%	38	2,080	1,007
				Averages	**2,914**	**1,164**

* Rough Rider drilling participation agreement wells where our working interest is anticipated to increase upon payout.

** Excludes any days well was down for remediation.

During 2011, we anticipate spending approximately $582.1 million to drill and complete an anticipated 65.7 net wells. Additionally, we anticipate spending approximately $27.4 million on land. Finally, we anticipate spending approximately $83.2 million on support infrastructure to expand our gathering systems in Williams and McKenzie Counties, North Dakota and to add additional water disposal wells. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Capital Commitments — Overview of Capital Activity."

Onshore Gulf Coast Province

Our Onshore Gulf Coast province is a high potential, multi-pay province that lends itself to 3-D seismic exploration due to its substantial structural and stratigraphic complexity. We believe our established 3-D seismic exploration approach, combined with our exploration staff's extensive experience and accumulated knowledge base in the Onshore Gulf Coast province provides us with significant competitive advantages.

Since 2009, activity in the onshore Gulf Coast province has been significantly reduced due to depressed natural gas prices and our allocation of capital to the Williston Basin, which is predominately crude oil. During 2010, we completed two gross wells (2.0 net) in two attempts for a completion rate of 100%. In 2010, we spent $16.4 million on drilling and land in our Onshore Gulf Coast province, before the impact of asset sale proceeds. In 2011, we have no current plans to drill in the Onshore Gulf Coast province.

Anadarko Basin Province

The Anadarko Basin is located in the Texas Panhandle and Western Oklahoma. We believe this prolific natural gas producing province offers a combination of relatively lower risk exploration and development opportunities in shallower horizons, as well as higher risk, but higher reserve potential opportunities in the deeper sections that have been relatively under explored. In addition, drilling economics in the Anadarko Basin are enhanced by the multi-pay nature of many of the prospects, with secondary or tertiary targets serving as either incremental value or as alternatives if the primary target zone is not productive.

As with our Onshore Gulf Coast province, our activity in the Anadarko Basin has been significantly reduced since 2009. In 2010, we spent $0.7 million in the Anadarko Basin before the impact of asset sale proceeds. In 2011, we anticipate spending $1.6 million to drill 6 gross (0.6 net) wells in the Anadarko Basin.

West Texas and Other Province

The Permian Basin of West Texas and Eastern New Mexico is a predominantly crude oil producing province with generally longer life reserves than that of our onshore Gulf Coast.

During 2010, we completed 15 gross (2.6 net) Wolfberry wells in West Texas at a 100% completion rate and spent a total of $4.8 million on drilling and land, before the impact of asset sale proceeds. In the second quarter 2010, we completed the sale of a portion of our proved developed reserves totaling approximately 0.6 MMboe. The primary assets remaining in our West Texas province are approximately 2,050 net acres prospective for the Wolfberry. In 2011, we anticipate spending $3.1 million to drill 15 gross (1.8 net) wells in West Texas.

In the fourth quarter of 2010, we divested all of our acreage in the Powder River Basin in Wyoming for proceeds totaling approximately $4.0 million.

Title to Properties

We believe we have satisfactory title, in all material respects, to substantially all of our producing properties in accordance with standards generally accepted in the oil and natural gas industry. Our properties are subject to royalty interests, standard liens incident to operating agreements, liens for current taxes and other burdens, which we believe do not materially interfere with the use of or affect the value of such properties. Substantially all of our proved crude oil and natural gas properties are pledged as collateral for borrowings under our Senior Credit Facility. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Senior Credit Facility" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Senior Notes."

Crude Oil and Natural Gas Reserves

Our estimated total net proved reserves of crude oil and natural gas as of December 31, 2010 are as follows:

Summary of Crude Oil and Natural Gas Reserves as of Fiscal-Year-End Based on Average Fiscal-Year Prices

	Reserves		
	Crude oil (MMBbls)	NaturalGas (Bcf)	Total (MMBoe)(a)
PROVED			
Developed:			
United States	17.5	36.5	23.6
Undeveloped:			
United States	34.7	51.3	43.2
TOTAL PROVED	52.2	87.8	66.8

(a) Boe is defined as one barrel of oil equivalent determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Our internal control procedures require that our reserve report is prepared by a third party engineering firm at the end of every year based on information provided by our Reservoir Engineering Department. Our Chief Reservoir and Acquisitions Engineer reviews and approves the reserve information compiled by our internal staff and is the technical person primarily responsible for overseeing the preparation of our reserve estimates. He has a degree in Petroleum Engineering from Texas A&M University and over 26 years experience in the industry, including SEC compliance with respect to proved reserves. He is licensed professional engineer in the State of Texas (PE 76121). Our internal staff of petroleum engineers, geoscience professionals and petroleum landmen work closely with CGA, our third party reserve engineers, to ensure the integrity, accuracy and timeliness of data furnished to CGA in their reserves estimation process. CGA is a Texas Registered Engineering Firm (F-693). Our primary contact at CGA is Mr. W. Todd Brooker, Vice President. Mr. Brooker is a State of Texas Licensed Professional Engineer (License #83462).

All key parameters in the reserve information are reviewed and approved by our executive officers. Our technical team meets regularly with representatives of CGA to review properties and discuss the methods and assumptions used by CGA in their preparation of the year-end reserves estimates. Our technical team and Chief Reservoir and Acquisitions Engineer also meets regularly with our Executive Vice President — Operations and our Executive Vice President — Exploration to review the methods and assumptions used by CGA in their preparation of the year-end reserves estimates. A copy of the CGA reserve report and detailed reserve analysis are reviewed by our audit committee with representatives of CGA and our internal technical staff before dissemination of the information.

In accordance with applicable requirements of the SEC, estimates of our net proved reserves and future net revenues are made using average prices at the beginning of each month in the 12-month period prior to the date of such reserve estimates and are held constant throughout the life of the properties (except to the extent a contract specifically provides for escalation). Estimated quantities of net proved reserves and future net revenues therefrom are affected by crude oil and natural gas prices, which have fluctuated widely in recent years. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Policies — New Accounting Pronouncements."

There are numerous uncertainties inherent in estimating crude oil and natural gas reserves and their estimated values, including many factors beyond our control. The reserve data set forth in the CGA report represents only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geologic interpretation and judgment. As a result, estimates of different engineers, including those used by us, may vary. In addition, estimates of reserves are subject to revision based upon actual production, results of future development and exploration activities, prevailing crude 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 crude oil and natural gas that are ultimately recovered and are highly dependent upon the accuracy of the assumptions upon which they are based. Our estimated net proved reserves, included in our SEC filings, have not been filed with or included in reports to any other federal agency. See "Item 1A. Risk Factors — Although our crude oil and natural gas reserve data is independently estimated, these estimates may still prove to be inaccurate."

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

Proved Undeveloped Reserves

Our total proved undeveloped (PUD) reserves as of December 31, 2010 were 43.2 MMBoe, or 65% of our total proved reserves. Our PUD reserves as of December 31, 2009 were 17.5 MMBoe and represented 63% of our total proved reserves.

The increase in our year-end 2010 PUD reserves is attributable to both the increased level of our drilling activity and the continued application of advance drilling and completion techniques in the Williston Basin. During 2010, we had drilled and completed, were completing or were drilling 41.6 net wells versus 6.9 net wells in 2009. Our advanced techniques incorporate drilling long lateral horizontal wellbores approximately 10,000' in length and completing wells with multi-stage fracture stimulations ranging typically from 30 to 38 fracture stimulations, which has improved our estimated ultimate recoveries. During 2010, we implemented widespread application of our advanced drilling and completion techniques in Mountrail, Williams and McKenzie Counties, North Dakota and drilled our initial well in Roosevelt County, Montana. In these areas, we were able to increase our level of PUD reserves.

Partially offsetting the above Williston Basin PUD reserve increases, we eliminated multiple PUD reserve locations in the Onshore Gulf Coast province that were primarily conventional natural gas targets that we currently do not anticipate drilling within the next five years. The PUD reserve locations that we eliminated totaled 0.8 MMBoe.

Our PUD reserves also decreased due to the drilling of 33 gross PUD wells (13.2 net) during 2010. During the year, we spent approximately $95.9 million dollars converting 5.5 MMBoe from PUD to proved developed producing reserves.

Reconciliation of Standardized Measure to Pre-tax PV10%

Pre-tax PV10% is the estimated present value of the future net revenues from our proved crude oil and natural gas reserves before income taxes discounted using a 10% discount rate. Pre-tax PV10% is considered a non-GAAP financial measure under SEC regulations because it does not include the effects of future income taxes, as is required in computing the standardized measure of discounted future net cash flows. We believe that pre-tax PV10% is an important measure that can be used to evaluate the relative significance of our crude oil and natural gas properties and that pre-tax PV10% is widely used by securities analysts and investors when evaluating oil and natural gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, the use of a pre-tax measure provides greater comparability of assets when evaluating companies. We believe that most other companies in the oil and natural gas industry calculate pre-tax PV10% on the same basis. Pre-tax PV10% is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting income taxes. The table below provides a reconciliation of our standardized measure of discounted future net cash flows to our pre-tax PV10% value (in millions).

	At December 31,		
	2010	2009	2008
Standardized measure of discounted future net cash flows	$ 866.1	$ 246.5	$ 279.3
Add present value of future income tax discounted at 10%	242.6	7.6	8.7
Pre-tax PV10%	$ 1,108.7	$ 254.1	$ 288.0

Drilling Activities

We drilled and completed, or participated in the drilling and completion of, the following wells during the periods indicated.

	Year Ended December 31,					
	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Natural gas	0	0.0	0	0.0	4	1.3
Crude oil	1	1.0	1	0.1	1	0.8
Non-productive	0	0.0	1	0.2	2	1.0
Total	1	1.0	2	0.3	7	3.1
Development wells:						
Natural gas	7	2.1	1	0.6	9	4.5
Crude oil	125	31.1	51	6.9	52	7.8
Non-productive	0	0.0	0	0.0	0	0.0
Total	132	33.2	52	7.5	61	12.3

Present Activities

As of December 31, 2010, we had seven operated drilling rigs in the Williston Basin. Four drilling rigs were drilling development locations representing 2.2 net wells, two drilling rigs were in the process of rigging down and one drilling rig was in the process of rigging up. At year-end, we also had 17 non-operated wells drilling in the Williston Basin representing 0.5 net wells. We had 11 operated wells in the Williston Basin waiting on completion representing 7.6 net wells and one operated well in the Williston Basin fracing representing 0.3 net wells. Finally, we had 24 non-operated Williston Basin wells waiting on completion representing 1.4 net wells.

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

Delivery Commitments

We have committed to deliver all of our natural gas from our lands and leases in Williams County, North Dakota for the next seven years to a single purchaser. We must deliver a minimum of 2,500 mcf per day for the first year and 5,000 mcf per day for the subsequent four years. We will pay a penalty for volume deficiencies except in certain circumstances. We will receive 70% of the purchaser's proceeds minus certain adjustments. The purchaser is required to pay for all facilities required to receive our gas from existing wells and the entire cost to connect for subsequent wells located within two miles of the purchaser's gathering system. For subsequent wells located more than two miles from the purchaser's gathering system, the purchaser may elect to either pay the cost to connect for the first two miles and require us to pay the cost to connect for the remainder or not to connect the well. If the purchaser elects not to connect the subsequent well, we can request the well and any others within that spacing unit be released from the terms of the agreement. Additionally, contingent upon completion of pipelines from the Williston Basin to Guernsey, Wyoming and Cushing, Oklahoma, we have entered into agreements with a marketing company to deliver an average of 5,000 barrels of oil per day and 10,000 barrels of oil per day, respectively for five years. We have the right to terminate this agreement if the pipelines are not in service by December 31, 2012 and December 31, 2013, respectively. We will pay a penalty for volume deficiencies except in certain circumstances. We will receive NYMEX near month WTI minus certain adjustments and a marketing fee. We have determined that we will have sufficient production to meet these commitments.

Productive Wells and Acreage

Productive Wells

The following table sets forth our ownership interest at December 31, 2010 in productive crude oil and natural gas wells in the areas indicated. Wells are classified as crude oil or natural gas according to their predominant production stream. Gross wells are the total number of producing wells in which we have an interest, and net wells are determined by multiplying gross wells by our average working interest.

	Natural Gas		Crude oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Williston Basin	0	0.0	237	61.0	237	61.0
Onshore Gulf Coast	68	40.4	17	4.1	85	44.5
Anadarko Basin	79	22.1	10	1.5	89	23.6
West Texas and Other	0	0.0	31	7.6	31	7.6
Total	147	62.5	295	74.2	442	136.7

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.

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 crude oil and natural gas, regardless of whether or not such acreage contains proved reserves. The following table sets forth the approximate developed and undeveloped acreage that we held as leasehold interest at December 31, 2010.

	Developed(a)		Undeveloped(a)		Total	
	Gross	Net	Gross	Net	Gross	Net
Williston Basin	131,531	87,273	469,070	277,036	600,601	364,309
Onshore Gulf Coast	21,627	9,077	5,016	2,985	26,643	12,062
Anadarko Basin	61,529	17,498	7,136	5,110	68,665	22,608
West Texas and Other	11,928	2,316	6,508	756	18,436	3,072
Total	226,615	116,164	487,730	285,887	714,345	402,051

(a) Does not include acreage for which assignments have not been received.

All of our leases for undeveloped acreage summarized in the preceding table will expire at the end of their respective primary terms unless we renew the existing leases, we establish production from the acreage, or some other "savings clause" is exercised. The following table sets forth the minimum remaining lease terms for our gross and net undeveloped acreage.

	Acres Expiring	
Twelve Months Ending:	**Gross**	**Net**
December 31, 2011	110,129	54,477
December 31, 2012	159,025	95,979
December 31, 2013	155,224	81,771
December 31, 2014	36,045	28,806
December 31, 2015	7,358	4,928
Thereafter	19,949	19,926
Total	487,730	285,887

In addition, as of December 31, 2010, we had mineral interests covering approximately 13,408 gross and 2,100 net acres including 264 net acres in the Williston Basin. The mineral acres will continue into perpetuity and will not expire.

Sales Volumes, Prices and Production Costs

The following table sets forth our sales volumes for the Williston Basin.

	Year Ended December 31,		
	2010	**2009**	**2008**
Sales volumes(a):			
Crude oil volumes (MBbls)			
Williston Basin	2,026	607	285
Natural gas volumes (MMcf)			
Williston Basin	940	163	50

The following table sets forth the average prices we received before hedging, the average prices we received including hedging settlement gains (losses), the average price including hedging settlements and unrealized gains (losses) and average production costs associated with our sale of crude oil and natural gas for the periods indicated. We account for our hedges using mark-to-market accounting, which requires that we record both derivative settlements and unrealized gains (losses) to the consolidated statement of operations within a single income statement line item. We have elected to include both derivative settlements and unrealized gains (losses) within revenue.

	2010	2009	2008
Average crude oil prices based on sales volumes:			
Crude oil price (per Bbl)	$ 71.08	$ 54.79	$ 89.06
Crude oil price including derivative settlement gains (losses) (per Bbl)	$ 70.87	$ 53.99	$ 84.63
Crude oil price including derivative settlements and unrealized gains (losses) (per Bbl)	$ 64.55	$ 48.65	$ 89.79
Average natural gas prices based on sales volumes:			
Natural gas price (per Mcf)	$ 5.23	$ 4.01	$ 9.21
Natural gas price including derivative settlement gains (losses) (per Mcf)	$ 6.02	$ 5.71	$ 9.08
Natural gas price including derivative settlements and unrealized gains (losses) (per Mcf)	$ 6.16	$ 5.21	$ 9.48
Average equivalent prices based on sales volumes:			
Oil equivalent price (per Boe)	$ 60.84	$ 37.97	$ 65.50
Oil equivalent price including derivative settlement gains (losses) (per Boe)	$ 61.90	$ 43.19	$ 63.62
Oil equivalent price including derivative settlements and unrealized gains (losses) (per Boe)	$ 57.43	$ 39.12	$ 66.84
Average production costs (per Boe) based on sales volumes:			
Lease operating expenses (includes costs for operating and maintenance and expensed workovers)	$ 6.03	$ 7.61	$ 5.89
Ad valorem taxes	$ 0.30	$ 0.56	$ 0.58
Production taxes	$ 5.88	$ 2.84	$ 2.81

(a) Sales volumes for 2010 and 2009 exclude 29,654 and 16,475 barrels of crude oil produced during the year and added to inventory during the respective period. Ending inventory at year end 2008 was not material.

Item 3. ***Legal Proceedings***

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

As of December 31, 2010, there are no known environmental or other regulatory matters related to our operations that are reasonably expected to result in a material liability to us. Compliance with environmental laws and regulations has not had, and is not expected to have, a material adverse effect on our capital expenditures.

Item 4. Removed and Reserved.

Executive Officers of the Registrant

Pursuant to Instruction 3 to Item 401(b) of Regulation S-K and General Instruction G(3) to Form 10-K, the following information is included in Part I of this report. The following are our executive officers as of February 25, 2010.

Name	Age	Position
Ben M. Brigham	51	Chief Executive Officer, President and Chairman
Eugene B. Shepherd, Jr.	52	Executive Vice President and Chief Financial Officer
David T. Brigham	50	Executive Vice President — Land and Administration and Director
A. Lance Langford	48	Executive Vice President — Operations
Jeffery E. Larson	52	Executive Vice President — Exploration

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

Eugene B. Shepherd, Jr. has served as Executive Vice President and Chief Financial Officer since October 2003, and previously served as Chief Financial Officer from June 2002 to October 2003. Mr. Shepherd has approximately 27 years of financial and operational experience in the energy industry. Prior to joining us, Mr. Shepherd served as Integrated Energy Managing Director for the investment banking division of ABN AMRO Bank, where he executed merger and acquisition advisory, capital markets and syndicated loan transactions for energy companies. Prior to joining ABN AMRO, Mr. Shepherd spent fourteen years as an investment banker for Prudential Securities Incorporated, Stephens Inc. and Merrill Lynch Capital Markets. Mr. Shepherd worked as a petroleum engineer for over four years for both Amoco Production Company and the Railroad Commission of Texas. He holds a B.S. in Petroleum Engineering and an MBA, both from the University of Texas at Austin.

David T. Brigham joined us in 1992 and has served as a Director since May 2003 and as Executive Vice President — Land and Administration since June 2002. Mr. Brigham served as Senior Vice President — Land and Administration from March 2001 to June 2002, Vice President — Land and Administration from February 1998 to March 2001, as Vice President — Land and Legal from 1994 until February 1998 and as Corporate Secretary from February 1998 to September 2002. From 1987 to 1992, Mr. Brigham worked as an attorney in the energy section with Worsham, Forsythe, Sampels & Wooldridge. For a brief period of time before attending law school, Mr. Brigham was a landman for Wagner & Brown Oil and Gas Producers, an independent oil and gas exploration and production company. Mr. Brigham holds a B.B.A. in Petroleum Land Management from the University of Texas and a J.D. from Texas Tech School of Law. Mr. Brigham is the brother of Ben M. Brigham, Chief Executive Officer, President and Chairman of the Board.

A. Lance Langford joined us in 1995 as Manager of Operations, served as Vice President - Operations from January 1997 to March 2001, served as Senior Vice President — Operations from March 2001 to September 2003 and has served as Executive Vice President — Operations since September 2003. From 1987 to 1995, Mr. Langford served in various engineering capacities with Meridian Oil Inc., handling a variety of reservoir, production and drilling responsibilities. Mr. Langford holds a B.S. in Petroleum Engineering from Texas Tech University.

Jeffery E. Larson joined us in 1997 and was Vice President — Exploration from August 1999 to March 2001, Senior Vice President — Exploration from March 2001 to September 2003 and has served as Executive Vice President — Exploration since September 2003. Prior to joining us, Mr. Larson was an explorationist in the Offshore Department of Burlington Resources, a large independent exploration company, where he was responsible for generating exploration and development drilling opportunities. Mr. Larson worked at Burlington from 1990 to 1997 in various roles of responsibility. Prior to Burlington, Mr. Larson spent five years at Exxon as a Production Geologist and Research Scientist. He holds a B.S. in Earth Science from St. Cloud State University in Minnesota and a M.S. in Geology from the University of Montana.

PART II

Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Price Range of Common Stock, Performance Graph, and Dividend Policy

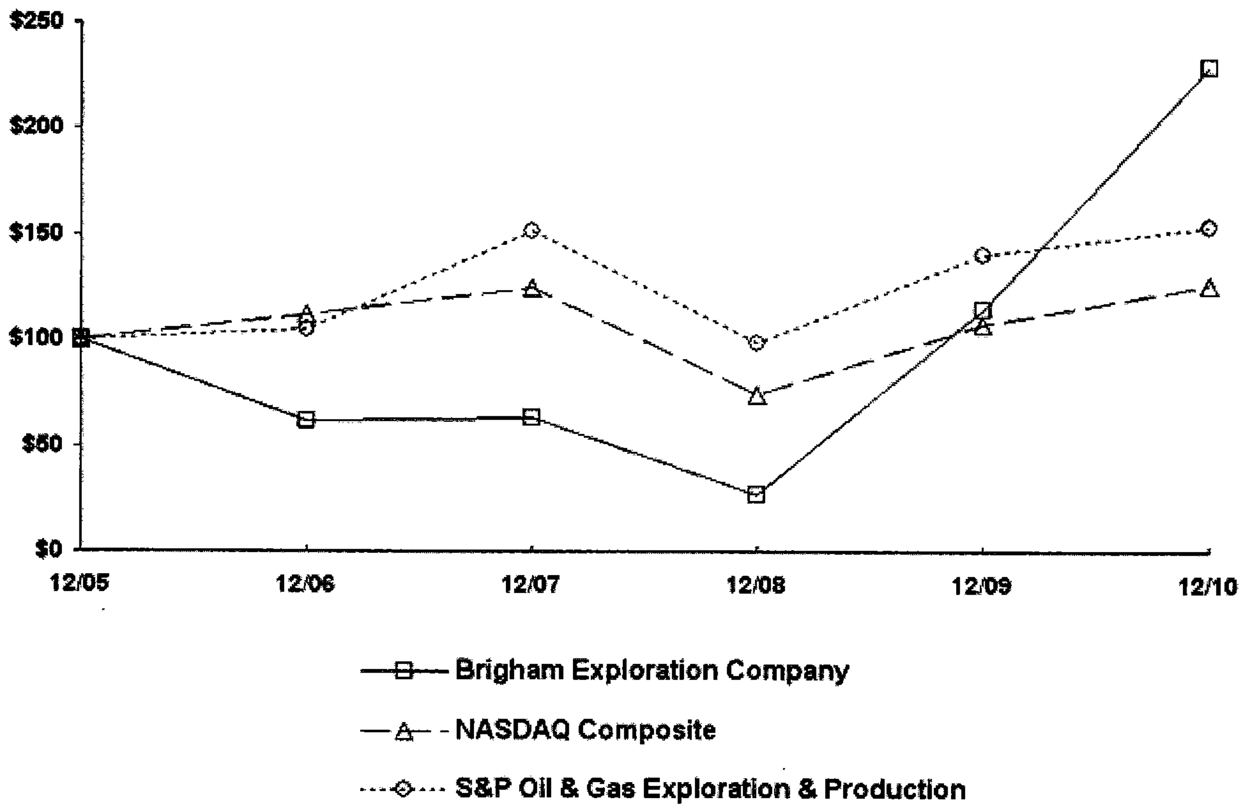
Our common stock commenced trading on the NASDAQ Global Select Market (formerly the NASDAQ National Market) on May 8, 1997 under the symbol "BEXP." The following table sets forth the high and low intra-day sales prices per share of our common stock for the periods indicated on the NASDAQ Global Select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

	High	Low
2009:		
First Quarter	$ 4.25	$ 1.04
Second Quarter	4.30	1.60
Third Quarter	10.61	2.50
Fourth Quarter	14.93	7.99
2010:		
First Quarter	$ 18.00	$ 12.58
Second Quarter	21.15	13.45
Third Quarter	19.15	14.18
Fourth Quarter	28.15	18.55

The closing market price of our common stock on February 23, 2011 was $33.86 per share. As of February 23, 2011, there were an estimated 145 record owners of our common stock.

The following graph is a comparison of cumulative total returns. It assumes that $100 was invested in our common stock, the NASDAQ Composite Index, and the S&P Oil & Gas Exploration and Production Index at the end of 2005 and remained invested through year-end 2010. The Indices and the graph were prepared by an independent third party. The NASDAQ Composite Index is calculated using the over 3,000 companies which trade on The NASDAQ Stock Market, including both domestic and foreign companies. The S&P Oil & Gas Exploration and Production Index (SPSIOP) represents the oil and gas exploration and production sub-industry portion of the S&P Total Market Index.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*
Among Brigham Exploration Company, The NASDAQ Composite Index
And The S&P Oil & Gas Exploration & Production Index



* $100 invested on 12/31/05 in stock or index, including reinvestment of dividends. Fiscal years ending December 31.

No dividends have been declared or paid on our common stock to date. We intend to retain all future earnings for the development of our business. Our Senior Credit Facility and our Senior Notes restrict our ability to pay dividends on our common stock.

Securities Authorized for Issuance under Equity Compensation Plans

The following table includes information regarding our equity compensation plans as of the year ended December 31, 2010.

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options	Weighted-Average Price of Outstanding Options	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans
Equity compensation plans approved by security holders(a)	741,037	$ 8.41	2,262,815
Equity compensation plans not approved by security holders	—	—	—
Total	741,037	$ 8.41	2,262,815

(a) Does not include 530,883 shares of restricted stock issued and outstanding at December 31, 2010.

Issuer Purchases of Equity Securities

In 2010, we elected to allow employees to deliver shares of vested restricted stock with a fair market value equal to their federal, state and local tax withholding amounts on the date of issue in lieu of cash payment.

Period	Total Number of Shares Purchased	Average Price Paid per Share
October 2010	2,520	$ 21.01
Total	2,520	21.01

Item 6. *Selected Consolidated Financial Data*

This section presents our selected consolidated financial data and should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and related notes included in "Item 8. Financial Statements and Supplementary Data." The selected consolidated financial data in this section is not intended to replace our consolidated financial statements.

We derived the statement of operations data and statement of cash flows data for the years ended December 31, 2010, 2009 and 2008, and balance sheet data as of December 31, 2010 and 2009 from the audited consolidated financial statements included in this report. We derived the statement of operations data and statement of cash flows data for the years ended December 31, 2007 and 2006 and the balance sheet data as of December 31, 2008, 2007 and 2006, from our accounting books and records.

	Year Ended December 31,				
	2010	2009	2008	2007	2006
	(In thousands, except per share information)				
Statement of Operations Data:					
Revenues:					
Crude oil and natural gas sales	$ 179,279	$ 68,192	$ 125,108	$ 120,557	$ 102,835
Gain (loss) on derivatives, net	(10,066)	2,064	2,548	(1,664)	3,335
Support infrastructure revenue	489	—	—	—	—
Other revenue	20	88	132	88	127
Total revenues	169,722	70,344	127,788	118,981	106,297
Costs and expenses:					
Lease operating	18,651	14,655	12,363	10,704	10,701
Production taxes	17,313	5,098	5,374	2,541	4,021
Support infrastructure expenses	50	—	—	—	—
General and administrative	12,943	9,243	9,557	9,276	7,887
Depletion of crude oil and natural gas properties	58,195	32,054	53,498	59,079	46,386
Impairment of crude oil and natural gas properties	—	114,781	237,180	6,505	—
Depreciation and amortization	1,704	812	629	613	537
Loss on inventory valuation	—	2,196	—	—	—
Accretion of discount on asset retirement obligations	422	421	361	379	317
Total costs and expenses	109,278	179,260	318,962	89,097	69,849
Operating income (loss)	60,444	(108,916)	(191,174)	29,884	36,448
Other income (expense):					
Interest income	1,198	578	191	654	1,207
Interest expense, net	(11,448)	(16,431)	(14,495)	(14,622)	(9,688)
Gain loss on derivatives, net	—	—	—	—	3,213
Loss on early redemption of Senior Notes	(11,308)	—	—	—	—
Other income (expense)	5,094	1,544	530	1,022	1,352
Total other income (expense)	(16,464)	(14,309)	(13,774)	(12,946)	(3,916)
Income (loss) before income taxes and cumulative effect of change in accounting principle	43,980	(123,225)	(204,948)	16,938	32,532
Income tax benefit (expense):					
Current	—	—	—	—	—
Deferred	(1,084)	233	42,701	(6,728)	(12,744)
	(1,084)	233	42,701	(6,728)	(12,744)
Net income (loss) available to common stockholders	$ 42,896	$ (122,992)	$ (162,247)	$ 10,210	$ 19,788
Net income (loss) per share available to common shareholders:					
Basic	$ 0.39	$ (1.74)	$ (3.57)	$ 0.23	$ 0.44
Diluted	0.38	(1.74)	(3.57)	0.22	0.43
Weighted average shares outstanding:					
Basic	111,355	70,569	45,441	45,110	45,017
Diluted	113,308	70,569	45,441	45,531	45,597

	At December 31,				
	2010	2009	2008	2007	2006
			(In thousands)		
Statement of Cash Flows Data:					
Net cash provided (used) by:					
Operating activities	$ 144,520	$ 51,750	$ 69,630	$ 90,449	$ 88,687
Investing activities	(556,211)	(164,620)	(179,866)	(99,093)	(171,747)
Financing activities	394,653	113,608	136,416	18,207	83,385
Balance Sheet Data:					
Cash and cash equivalents	$ 23,743	$ 40,781	$ 40,043	$ 13,863	$ 4,300
Investments	223,991	80,093	—	—	—
Crude oil and natural gas properties, using the full cost method of accounting, net	669,356	330,733	404,839	510,207	485,525
Total assets	1,085,401	498,256	489,056	548,428	522,587
Long-term debt	300,000	158,968	303,730	168,492	149,334
Series A preferred stock, mandatorily redeemable (a)	—	10,101	10,101	10,101	10,101
Total stockholders' equity	593,270	264,283	121,269	279,027	266,015

(a) At year-end 2009, our Series A preferred stock was classified as a current liability as it was scheduled to be redeemed in 2010. Our Series A preferred stock was redeemed in the second quarter 2010.

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

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

Sources of Our Revenues

We derive our revenues from the sale of crude oil and natural gas that is produced from our properties. Revenues are a function of the production volumes sold and the prevailing market prices at the time of sale.

To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we utilize derivative instruments to hedge future sales prices on a portion of our oil and natural gas production. Our current strategy is to hedge up to 100% of our proved developed producing (PDP) oil volumes and up to 50% of the forecasted oil volumes associated with our Williston Basin drilling program for the upcoming 24 months. The use of certain types of derivative instruments may prevent us from realizing the benefit of upward price movements. See "Item 1A. Risk Factors — Our hedging activities may prevent us from benefiting from price increases and may expose us to other risks."

Components of Our Cost Structure

Production Costs are the day-to-day costs we incur to bring hydrocarbons out of the ground and to the market combined with the daily costs we incur to maintain our producing properties. This includes lease operating expenses and production taxes.

- Lease operating expenses are generally comprised of several components including: the cost of labor and supervision to operate our wells and related equipment; repairs and maintenance; fluid treatment and disposal; related materials, supplies, and fuel; and insurance applicable to our wells and related facilities and equipment. Lease operating expenses also include the cost for expensed workovers. Lease operating expenses are driven in part by the type of commodity produced, the level of workover activity and the geographical location of the properties.

- Lease operating expenses also include ad valorem taxes, which are imposed by local taxing authorities such as school districts, cities, and counties or boroughs. The amount of tax we pay is based on a percent of value of the property assessed or determined by the taxing authority on an annual basis. When crude oil and natural gas prices rise, the value of our underlying property interests increase, which results in higher ad valorem taxes.

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

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

Depreciation, Depletion and Amortization is the systematic expensing of the capital costs incurred to acquire, explore and develop crude oil and natural gas. As a full cost company, we capitalize all direct costs associated with our exploration and development efforts, including a portion of our interest and certain general and administrative costs, and apportion these costs to each unit of production sold through depletion expense. Generally, if reserve quantities are revised up or down, our depletion rate per unit of production will change inversely. When the depreciable capital cost base increases or decreases, the depletion rate will move in the same direction.

Asset Retirement Accretion Expense is the systematic, monthly accretion of future abandonment costs of tangible assets such as wells, service assets, pipelines, and other facilities.

General and Administrative Expense includes payroll and benefits for our corporate staff, costs of maintaining our headquarters, managing our production and development operations and legal compliance. We capitalize general and administrative costs directly related to prospect generation and our exploration activities.

Interest. We have relied on our Senior Credit Facility to fund our short-term liquidity (working capital) and a portion of our long-term financing needs. The interest rate that we pay on our Senior Credit Facility correlates with both fluctuations in interest rates and the amount outstanding under the facility. We pay a fixed interest rate on our Senior Notes. We expect to continue to incur interest expense as we continue to use debt to fund a portion of our capital expenditures. We capitalize interest directly related to our unevaluated properties and certain properties under development, which are not being amortized.

Income Taxes. We are generally subject to a 35% federal income tax rate. For income tax purposes, we are allowed deductions for accelerated depreciation, depletion, intangible drilling costs, and state taxes. Through 2010, all of our federal and state income taxes were deferred.

Capital Commitments

Our primary needs for cash are to fund our capital expenditure program, our working capital obligations and for the repayment of contractual obligations. In the future, cash will also be required to fund our capital expenditures for the exploration and development of properties necessary to offset the inherent declines in production and proven reserves that are typical in an extractive industry like ours and also to hold acreage that would otherwise expire if not drilled. Future success in growing reserves and production will be highly dependent on our access to cost effective capital resources and our success in economically finding and producing additional crude oil and natural gas reserves. Funding for our exploration and development of crude oil and natural gas activities and the repayment of our contractual obligations may be provided by any combination of cash flow from operations, cash on our balance sheet, the unused committed borrowing capacity under our Senior Credit Facility, reimbursements of prior land and seismic costs by third parties who participate in our projects, and the sale of interests in projects and properties or alternative financing sources as discussed in "- Contractual Obligations" and "- Liquidity and Capital Resources." Cash flows from operations and the unused committed borrowing capacity under our Senior Credit Facility fund our working capital obligations.

Overview of Capital Activity

The application of advanced drilling and completion technologies in the Williston Basin and the associated improvements in well economics as well as the commodity price advantage of crude oil relative to natural gas has led us to increase both the total amount of capital expended and the percentage allocation of our capital budget to the Williston Basin and to decrease our spending in our other conventional natural gas focused provinces.

In October 2009, we completed a public offering of common stock and raised $168.3 million in net proceeds in order to pre-fund an increased level drilling activity in 2010. Our preliminary 2010 capital budget announced in October 2009, concurrent with the equity offering, was estimated to be $175.8 million. We estimated that we would have four drilling rigs running throughout 2010 in the Williston Basin and would drill 24 net Bakken and Three Forks wells.

In April 2010, we completed a public offering of common stock and raised $277.5 million in net proceeds in order to pre-fund a further acceleration in the Williston Basin. Our revised 2010 capital budget announced concurrent with the equity offering, was estimated to be $293.9 million. We estimated that we would add an incremental operated drilling rig every four months beginning May 2010 and would have eight operated rigs running in the Williston Basin by May 2011 and would therefore drill 31 net wells in the basin during 2010. Approximately $37.8 million of the aforementioned capital budget would be used to fund the construction of support infrastructure.

In August 2010, we revised our 2010 capital budget largely as a result of several large acreage acquisitions, which increased our acreage in the Williston Basin by approximately 52,800 net acres. Our revised capital budget announced in August 2010 was estimated to be approximately $404.0 million and included approximately 38 net Williston Basin wells and $95.7 million for land.

In September 2010, we issued $300 million in Senior Notes due 2018 to fund the tender offer for and redemption of our 9 5/8% Senior Notes due in 2014 and to pre-fund our 2011 capital budget and for general corporate purposes.

In November 2010, we revised our 2010 capital budget to $466.1 million largely as a result of the expectation of drilling and completing 45 net Williston Basin wells. We also increased our land budget and our support infrastructure budget by approximately $19 million and $3 million, respectively. See "Capital Expenditures" for a discussion of our 2011 budget.

Capital Expenditures

The timing of most of our capital expenditures is discretionary because we operate the majority of our wells. During 2010, we executed an agreement with a drilling contractor to enter into commitments for two walking drilling rigs for a three year period beginning upon their delivery date, which is anticipated to be in the first quarter 2012. Other than the aforementioned obligations, we have no material long-term capital expenditure commitments. Consequently, we have a significant degree of flexibility to adjust the level of our capital expenditures as circumstances warrant. Our capital expenditure program includes the following:

- cost of acquiring and maintaining our lease acreage position and our seismic resources;
- cost of drilling and completing new crude oil and natural gas wells;

- cost of installing and maintaining new support infrastructure;
- cost of maintaining, repairing and enhancing existing crude oil and natural gas wells;
- cost related to plugging and abandoning unproductive or uneconomic wells; and
- indirect costs related to our exploration activities, including payroll and other expenses attributable to our exploration professional staff.

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

The final determination with respect to our 2011 budgeted expenditures will depend on a number of factors, including:

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

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

Factors that could cause us to further increase our level of activity and capital budget in 2011 include an improvement in commodity prices or well performance that exceeds our risked forecasts, the divestiture of non-strategic conventional assets, a reduction in service and material costs, or the formation of joint ventures with other exploration and production companies outside of our core de-risked acreage positions in the Williston Basin, all of which would positively impact our operating cash flow.

Factors that would cause us to reduce our capital budget in 2011 include, but are not limited to, reductions in commodity prices or underperformance of wells relative to our risked forecasts or increases in service and materials costs, all of which would negatively impact our operating cash flow.

Our budgeted oil and gas capital expenditures for 2011 are as follows:

	2011 (In millions)
Drilling	$ 582.1
Support infrastructure	83.2
Land	27.4
Total oil and gas capital expenditures	$ 692.7

To support our prospect generation activities, we allocate a portion of our capital expenditures to land and seismic. Over the past three years, we have spent $162.9 million on land, excluding proceeds from asset sales, to expand our acreage position primarily in the Williston Basin.

For a more in depth discussion of our 2010 and 2011 capital expenditures see "Item 2. Properties."

Contractual Obligations

The following schedule summarizes our known contractual cash obligations at December 31, 2010 and the effect these obligations are expected to have on our future cash flow and liquidity.

	Payments Due by Year				
	Total	2011	2012	2013-2014	2015 and Thereafter
	(In thousands)				
Debt:					
Senior Notes	$ 300,000	$ —	$ —	$ —	$ 300,000
Senior Credit Facility	—	—	—	—	—
Total	$ 300,000	$ —	$ —	$ —	$ 300,000
Other commitments:					
Interest, Senior Notes(a)	$ 210,000	$ 26,250	$ 26,250	$52,500	$ 105,000
Interest, Senior Credit Facility(b)	—	—	—	—	—
Drilling rigs(c)	42,582	9,432	10,785	21,900	465
Non-cancelable operating leases	1,199	793	406	—	—
Total	$ 553,781	$ 36,475	$ 37,441	$74,400	$ 405,465

(a) Calculated assuming $300 million of Senior Notes outstanding and an interest rate of 8.75%. The payments are made in April and October until maturity in October 2018.

(b) Calculated assuming no amounts outstanding under our Senior Credit Facility. The interest rate under our facility is dependent upon Eurodollar borrowing rates plus a margin that fluctuates dependent upon the amount outstanding under the facility. The Eurodollar rate for one month borrowings was 0.32% on December 31, 2010. The amount of interest that we pay on amounts borrowed under our Senior Credit Facility will fluctuate over time as borrowings increase or decrease, as the applicable Eurodollar rate increases and decreases and as the applicable interest rate increases or decreases. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk — Interest Rate Risk."

(c) Contractual agreements with third-party service providers to procure drilling rigs for exploratory and development activities. See "Item 8. Financial Statements and Supplementary Data — Note 10 — Contingencies, Commitments and Factors Which May Affect Future Obligations."

We also have liabilities of $5.9 million related to asset retirement obligations on our Consolidated Balance Sheet as of December 31, 2010. Due to the nature of these obligations, we cannot determine precisely when payments will be made to settle these obligations. See "Item 8. Financial Statements and Supplementary Data — Note 7. Asset Retirement Obligations."

Crude Oil and Natural Gas Reserves

Our estimated total net proved reserves of crude oil and natural gas as of December 31, 2010, 2009 and 2008 were as follows.

	At December 31,		
	2010	2009	2008
Estimated Net Proved Reserves:			
Crude oil (MMBbls)	52.2	16.6	7.1
Natural gas (Bcf)	87.8	66.4	94.7
Oil equivalent (MMBoe)(a)	66.8	27.7	22.8
Proved developed reserves as a percentage of net proved reserves	35%	37%	46%

(a) Boe is defined as one barrel of oil equivalent determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Our estimated total net proved reserves increased 141% from 2009 to 2010. The increase in our year-end 2010 proved reserves is attributable to both the increased level of our drilling activity and the continued application of advance drilling and completion techniques in the Williston Basin. During 2010, we drilled and completed, were completing or were drilling 41.6 net wells versus 6.9 net wells in 2009. Our advanced techniques incorporate drilling long lateral horizontal wellbores approximately 10,000' in length and completing wells with multi-stage fracture stimulations ranging typically from 30 to 38 fracture stimulations, which has improved our rates of return. During 2010, we implemented widespread application of our advanced drilling and completion techniques in Mountrail, Williams and McKenzie Counties, North Dakota and drilled our initial well in Roosevelt County, Montana and drilled economic wells. In the Williston Basin, our reserves increased 260% to 55.4 MMBoe.

Partially offsetting our proved reserve increases, we eliminated multiple PUD reserve locations in our onshore Gulf Coast province where we currently do not anticipate drilling the locations within the next five years. The PUD reserve locations that we eliminated were primarily natural gas drilling locations in our South Texas acreage positions and totaled 0.8 MMBoe.

Results of Operations

Comparison of the twelve-month periods ended December 31, 2010, 2009 and 2008

Production volumes

	Year Ended December 31,				
	2010	% Change	2009	% Change	2008
Crude oil (MBbls)(a)	2,216	167%	830	44%	578
Natural gas (MMcf)	4,562	(23%)	5,892	(26%)	7,996
Total (MBoe)(b)	2,976	64%	1,812	(5%)	1,910
Average daily production volumes (Boe/d)(c)	8,267	64%	5,034	(5%)	5,306

(a) Includes approximately 29,654 and 16,475 barrels of oil produced in 2010 and 2009, respectively, and added to inventory in the respective year. Ending inventory at year end 2008 and was not material.

(b) Boe is defined as one barrel equivalent of crude oil, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

(c) Average daily production volumes calculated based on 360 day year.

Increase in Inventory During the Year

	Year Ended December 31,				
	2010	% Change	2009	% Change	2008
Crude oil (Bbls)	29,654	80%	16,475	NM	—
Natural gas (Mcf)	—	—	—	—	—
Total (Boe)	29,654	80%	16,475	NM	—

Sales volumes (Production volumes less increase in Inventory)

	Year Ended December 31,				
	2010	% Change	2009	% Change	2008
Crude oil (MBbls)(a)	2,186	169%	814	41%	578
Natural gas (MMcf)	4,562	(23%)	5,892	(26%)	7,996
Total (MBoe)(b)	2,947	64%	1,796	(6%)	1,910
Average daily sales volumes (Boepd)(c)	8,185	64%	4,988	(6%)	5,306

(a) Excludes approximately 29,654 and 16,475 barrels of oil produced in 2010 and 2009, respectively, and recorded as inventory at year-end. Ending inventory at year end 2008 was not material.

(b) Boe is defined as one barrel equivalent of crude oil, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

(c) Average daily sales volumes calculated based on 360 day year.

Our net equivalent sales volumes for 2010 increased by 64% to 2,947 MBoe (8,185 Boepd) from 1,796 MBoe (4,988 Boepd) in 2009. Our sales volumes for 2010 increased primarily due to our increased activity level in the Williston Basin, which drove crude oil sales volume growth of 169% from 2009 to 2010. This increase was partially offset by a 23% decrease in our natural gas volumes due to the natural decline of our wells. Crude oil as a percent of total production increased to 74% from 45% of our total production in 2010 and 2009, respectively, also as a result of our increased level of drilling activity in the Williston Basin.

The following is additional information regarding our 2010 sales volumes:

- Sales volumes from our Williston Basin province for 2010 increased 244% when compared to 2009. The increase was attributable to the rapid acceleration of our drilling activities in the Williston Basin. Sales volumes from this province represented 74% of our total sales volumes in 2010 versus 35% in 2009. Approximately 93% of our 2010 sales volumes from this province were oil compared to 96% in 2009.

- Sales volumes from our Onshore Gulf Coast province for 2010 decreased 36% when compared to 2009. The decrease in volumes was attributable to the reduction in our drilling activity in this province in order to focus our activities in the Williston Basin. Because of our limited drilling program, only limited new volumes were brought on line to offset the natural decline of our wells. Sales volumes from this province represented 17% of our total sales volumes in 2010 versus 44% in 2009. Approximately 82% of our 2010 sales volumes from this province were natural gas compared to 89% in 2009.

- Sales volumes from our Anadarko Basin province for 2010 decreased 23% when compared to 2009. The decrease in volumes was attributable to the reduction in drilling activity in this province in order to focus our activities in the Williston Basin. Because of the reduction in our drilling program in this province, limited new volumes were brought on line to offset the natural decline of our wells. Sales volumes from this province represented 7% of our volumes in 2010 versus 15% in 2009. Approximately 92% of our 2010 sales volumes from this province were natural gas compared to 92% in 2009.

- Sales volumes from our West Texas & Other province for 2010 decreased 45% when compared to 2009. The decrease in volumes was attributable to the reduction in our drilling activity in this province in order to focus our activities in the Williston Basin and the sale of producing properties in the second quarter 2010. Because of our limited drilling program, only limited new volumes were brought on line to offset the natural decline of our wells. Sales volumes from this province represented 2% of our total volumes in 2010 versus 6% in 2009. Approximately 87% of our 2010 sales volumes from this province were oil compared to 89% in 2009.

The following is additional information regarding our 2009 sales volumes.

- Sales volumes from our Williston Basin province for 2009 increased 116% when compared to 2008. The increase was attributable to the rapid escalation of our drilling activities in the Williston Basin. Sales volumes from this province represented 35% of our total volumes in 2009 versus 15% in 2008. Approximately 96% of our 2009 sales volumes from this province were oil compared to 97% in 2008.

- Sales volumes from our Onshore Gulf Coast province for 2009 decreased 32% when compared to 2008. The decrease in volumes was attributable to the reduction in our drilling activity in this province in order to focus our activities in the Williston Basin. Because of our limited drilling program, only limited new volumes were brought on line to offset the natural decline of our wells. Sales volumes from this province represented 44% of our total sales volumes in 2009 versus 61% in 2008. Approximately 89% of our 2009 sales volumes from this province were natural gas compared to 87% in 2008.

- Sales volumes from our Anadarko Basin province for 2009 decreased 20% when compared to 2008. The decrease in volumes was attributable to the reduction in drilling activity in this province in order to focus our activities in the Williston Basin. Because of the reduction in our drilling program in this province, no new volumes were brought on line to offset the natural decline of our wells. Sales volumes from this province represented 15% of our volumes in 2009 versus 17% in 2008. Approximately 92% of our 2009 sales volumes from this province were natural gas compared to 93% in 2008.

- Sales volumes from our West Texas & Other province for 2009 decreased 17% when compared to 2008. The decrease in volumes was attributable to the reduction in our drilling activity in this province in order to focus our activities in the Williston Basin. Because of our limited drilling program, only limited new volumes were brought on line to offset the natural decline of our wells. Sales volumes from this province represented 6% of our total volumes in 2009 versus 7% in 2008. Approximately 88% of our 2009 sales volumes from this province were oil compared to 88% in 2008.

Revenue, commodity prices and hedging

The following table shows our revenue from the sale of crude oil and natural gas for 2010, 2009 and 2008. Our commodity hedges are accounted for using mark-to-market accounting, which requires us to record both derivative settlements and unrealized derivative gains (losses) to the consolidated statement of operations within a single income statement line item. We include both derivative settlements and unrealized derivative gains (losses) within revenue.

	Year Ended December 31,				
	2010	% Change	2009	% Change	2008
	(In thousands, except per unit measurements)				
Crude oil revenue:					
Crude oil revenue	$155,403	249%	$ 44,580	(13%)	$ 51,449
Crude oil derivative settlement gains (losses)	(468)	(28%)	(654)	(74%)	(2,564)
Crude oil revenue including derivative settlements	$154,935	253%	$ 43,926	(10%)	$ 48,885
Crude oil derivative unrealized gains (losses)	(13,808)	218%	(4,343)	NM	2,983
Crude oil revenue including derivative settlements and unrealized gains (losses)	141,127	257%	39,583	(24%)	51,868
Natural gas revenue:					
Natural gas revenue	$ 23,876	1%	$ 23,612	(68%)	$ 73,659
Natural gas derivative settlement gains (losses)	3,577	(64%)	10,031	NM	(1,028)
Natural gas revenue including derivative settlements	$ 27,453	(18%)	$ 33,643	(54%)	$ 72,631
Natural gas derivative unrealized gains (losses)	633	NM	(2,970)	NM	3,157
Natural gas revenue including derivative settlements and unrealized gains (losses)	28,086	(8%)	30,673	(60%)	75,788
Crude oil and natural gas revenue:					
Crude oil and natural gas revenue	$179,279	163%	$ 68,192	(45%)	$ 125,108
Crude oil and natural gas derivative settlement gains (losses)	3,109	(67%)	9,377	NM	(3,592)
Crude oil and natural gas revenue including derivative settlement gains (losses)	182,388	135%	77,569	(36%)	121,516
Crude oil and natural gas derivative unrealized gains (losses)	(13,175)	80%	(7,313)	NM	6,140
Crude oil and natural gas revenue including derivative settlements and unrealized gains (losses)	169,213	141%	70,256	(45%)	127,656
Support infrastructure revenue	489	NM	—	NM	—
Other revenue	20	(77%)	88	(33%)	132
Total revenue	$169,722	141%	$ 70,344	(45%)	$ 127,788
Average crude oil prices (based on sales volumes):					
Crude oil price (per Bbl)	$ 71.08	30%	$ 54.79	(38%)	$ 89.06
Crude oil price including derivative settlement gains (losses) (per Bbl)	$ 70.87	31%	$ 53.99	(36%)	$ 84.63
Crude oil price including derivative settlements and unrealized gains (losses) (per Bbl)	$ 64.55	33%	$ 48.65	(46%)	$ 89.79

	Year Ended December 31,				
	2010	% Change	2009	% Change	2008
	(In thousands, except per unit measurements)				
Average natural gas prices:					
Natural gas price (per Mcf)	$ 5.23	30%	$ 4.01	(56%)	$ 9.21
Natural gas price including derivative settlement gains (losses) (per Mcf)	$ 6.02	5%	$ 5.71	(37%)	$ 9.08
Natural gas price including derivative settlements and unrealized gains (losses) (per Mcf)	$ 6.16	18%	$ 5.21	(45%)	$ 9.48
Average oil equivalent prices (based on sales volumes):					
Oil equivalent price (per Bbl)	$ 60.84	60%	$ 37.97	(42%)	$ 65.46
Oil equivalent price including derivative settlement gains (losses) (per bbl)	$ 61.90	43%	$ 43.19	(32%)	$ 63.60
Oil equivalent price including derivative settlements and unrealized gains (losses) (per Bbl)	$ 57.43	47%	$ 39.12	(41%)	$ 66.84

	2009 to 2010	2008 to 2009
Change in revenue from the sale of crude oil		
Price variance impact	$ 35,622	$ (27,885)
Sales volume variance impact	75,201	21,016
Cash settlement of derivative hedging contracts	186	1,910
Unrealized gains (losses) due to derivative hedging contracts	(9,465)	(7,326)
Total change	$ 101,544	$ (12,285)
Change in revenue from the sale of natural gas		
Price variance impact	$ 5,581	$ (30,657)
Sales volume variance impact	(5,317)	(19,390)
Cash settlement of derivative hedging contracts	(6,454)	11,059
Unrealized gains (losses) due to derivative hedging contracts	3,603	(6,127)
Total change	$ (2,587)	$ (45,115)
Change in revenue from the sale of crude oil and natural gas		
Price variance impact	$ 41,203	$ (58,542)
Volume variance impact	69,884	1,626
Cash settlement of derivative hedging contracts	(6,268)	12,969
Unrealized gains (losses) due to derivative hedging contracts	(5,862)	(13,453)
Total change	$ 98,957	$ (57,400)

Our 2010 crude oil and natural gas revenue including derivative settlements and unrealized gains (losses) increased $99.0 million, or 141% when compared to 2009. The following were the primary reasons for the increase in our revenue:

- a 169% increase in our crude oil sales volumes, which was partially offset by a 23% decrease in our natural gas sales volumes, increased revenue by $69.9 million;
- a 60% increase in the average crude oil equivalent price increased revenue by $41.2 million;
- a $3.1 million gain from the settlement of derivative contracts in 2010 versus a $9.4 million settlement gain in 2009 decreased revenue by $6.3 million; and
- a $13.2 million unrealized loss due to derivative hedging contracts in 2010 versus a $7.3 million unrealized loss due to derivative hedging contracts in 2009 decreased revenue by $5.9 million.

Our 2009 crude oil and natural gas revenue including derivative settlements and unrealized gains (losses) decreased $57.4 million, or 45% when compared to 2008. The following were the primary reasons for the decrease in our revenue:

- a 42% decrease in the average oil equivalent price decreased revenue by $58.5 million;
- a $7.3 million unrealized loss due to derivative hedging contracts in 2009 versus a $6.1 million unrealized gain due to derivative hedging contracts in 2008 decreased revenue by $13.5 million;
- an 41% increase in our crude oil sales volumes, which was partially offset by a 26% decrease in our natural gas sales volumes, increased revenue by $1.6 million; and
- a $9.4 million gain from the settlement of derivative contracts in 2009 versus a $3.6 million settlement loss in 2008 increased revenue by $13.0 million.

Support infrastructure. Revenue from support infrastructure comes from fees related to our support infrastructure assets in North Dakota, including fees from oil, natural gas, waste water and fresh water gathering lines. Our produced water disposal wells in our Ross and Rough Rider project areas became operational early in the fourth quarter 2010 and late in the fourth quarter 2010, respectively.

Other revenue. Other revenue relates to fees that we charge third parties who use our gas gathering systems to move their production from the wellhead to third party gas pipeline systems. Other revenue for 2010 was $20,000 compared to $88,000 in 2009 and $132,000 in 2008. Costs related to our gas gathering systems are recorded in lease operating expenses.

Hedging. We utilize costless collars, swaps, puts, and three way costless collars to (i) reduce the effect of price volatility on the commodities that we produce and sell, (ii) reduce commodity price risk and (iii) provide a base level of cash flow in order to assure we can execute at least a portion of our capital spending plans. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk — Derivative Instruments and Hedging Activities" for a description of our derivative contracts and our open derivative contracts.

The following table details derivative contracts that settled during 2010, 2009 and 2008 and includes the type of derivative contract, the volume, the weighted average NYMEX reference price for those volumes, and the associated gain /(loss) upon settlement.

	Year Ended December 31,				
	2010	% Change	2009	% Change	2008
Crude oil collars and three way costless collars					
Volumes (Bbls)	1,056,500	321%	251,000	38%	182,500
Average floor price (per Bbl)	$ 62.51	5%	$ 59.43	(15%)	$ 69.55
Average ceiling price (per Bbl)	$ 93.02	16%	$ 80.12	(15%)	$ 93.82
Gain /(loss) upon settlement (in thousands)	$ (468)	NM	$ 902	NM	$ (2,564)
Crude oil swaps					
Volumes (Bbls)	—	(100%)	90,000	NM	—
Average swap price (per Bbl)	$ —	(100%)	$ 50.75	NM	$ —
Gain /(loss) upon settlement (in thousands)	$ —	(100%)	$ (1,556)	NM	$ —
Total crude oil gain / (loss) upon settlement (in thousands)	$ (468)	(100%)	$ (654)	(75%)	$ (2,564)
Natural gas collars and three way costless collars					
Volumes (MMbtu)	2,730,000	39%	1,960,000	(60%)	4,850,000
Average floor price (per MMbtu)	$ 5.79	(19%)	$ 7.19	(6%)	$ 7.65
Average ceiling price (per MMbtu)	$ 7.36	(17%)	$ 8.83	(18%)	$ 10.75
Gain /(loss) upon settlement (in thousands)	$ 3,577	(56%)	$ 8,133	NM	$ (1,028)
Natural gas swaps					
Volumes (MMbtu)	—	(100%)	2,490,000	NM	—
Average swap price (per MMbtu)	$ —	(100%)	$ 4.359	NM	$ —
Gain /(loss) upon settlement (in thousands)	$ —	(100%)	$ 1,898	NM	$ —
Total natural gas gain /(loss) upon settlement (in thousands)	$ 3,577	(64%)	$ 10,031	NM	$ (1,028)

Operating costs and expenses

Production costs. We believe that per unit of production measures are the most effective basis for evaluating our production costs. We use this information to internally evaluate our performance, as well as to evaluate our performance relative to our peers.

	Unit-of-Production (Per Boe based on Sales Volumes) Year Ended December 31,				
Production costs:	2010	% Change	2009	% Change	2008
Operating & maintenance	$ 4.65	(23%)	$ 6.02	22%	$ 4.92
Expensed workovers	1.38	(13%)	1.58	65%	0.96
Ad valorem taxes	0.30	(46%)	0.56	(7%)	0.60
Lease operating expenses	$ 6.33	(22%)	$ 8.16	26%	$ 6.48
Production taxes	5.88	107%	2.84	1%	2.82
Production costs	$ 12.21	11%	$ 11.00	18%	$ 9.30

	Amount (In thousands) Year Ended December 31,				
Production costs:	2010	% Change	2009	% Change	2008
Operating & maintenance	$ 13,698	27%	$ 10,823	15%	$ 9,399
Expensed workovers	4,055	43%	2,832	53%	1,851
Ad valorem taxes	898	(10%)	1,000	(10%)	1,113
Lease operating expenses	$ 18,651	27%	$ 14,655	19%	$ 12,363
Production taxes	17,313	240%	5,098	(5%)	5,374
Production costs	$ 35,964	82%	$ 19,753	11%	$ 17,737

For 2010, our per unit production cost increased 11% when compared to 2009. The following were the primary reasons for the increase in our 2010 per unit production costs relative to 2009:

- production taxes increased 107% due to higher commodity sales prices and higher crude oil sales volumes in North Dakota, which are subject to an 11.5% tax rate; and

- higher production taxes were partially offset by 23% lower per unit lease operating expense, which was attributable to 64% higher sales volumes in 2010 as compared to that in 2009.

For 2009, our per unit production cost increased 18% when compared to 2008. The following were the primary reasons for the increase in our 2009 per unit production costs relative to 2008:

- O&M expenses increased 22%, or by $1.10 per Boe, due to increases in salt water disposal, compressor rental and overhead fees; and

- expensed workovers increased 65%, or by $0.62 per Boe, due to an increase in the number and cost of our workovers in 2009, in particular two workovers associated with our conventional natural gas wells.

Support infrastructure. We incur costs to operate our support infrastructure assets in North Dakota. Our produced water disposal wells in our Ross and Rough Rider project areas became operational early in the fourth quarter 2010 and late in the fourth quarter 2010, respectively.

General and administrative expenses. We capitalize a portion of our general and administrative costs. Capitalized costs include the cost of technical employees who work directly on our prospect generation and exploration activities and a portion of our associated technical organization costs such as supervision, telephone and postage.

	Year Ended December 31,				
	2010	% Change	2009	% Change	2008
	(In thousands, except per unit measurements which are based on sales volumes)				
General and administrative costs	$ 25,495	50%	$ 16,961	(3%)	$ 17,551
Capitalized general and administrative costs	(12,552)	63%	(7,718)	(4%)	(7,994)
General and administrative Expenses	$ 12,943	40%	$ 9,243	(3%)	$ 9,557
General and administrative expenses (per Boe)	$ 4.39	(15%)	$ 5.15	3%	$ 4.98

Our general and administrative expenses in 2010 increased $3.7 million from those in 2009. Before capitalization, our general and administrative costs increased by $8.5 million. The following were the primary reasons for the increase in our 2010 general and administrative costs relative to 2009:

- total compensation expense increased by $7.9 million due to the reinstatement of full salaries in late 2009 due to improved economic conditions, the reinstatement of our bonus plan in 2010, higher levels of employee salaries in 2010 to ensure competitive compensation levels with other oil and gas companies, and a higher number of employees due to our increased activity level in the Williston Basin; and

- other office expense increased by $0.6 million due to higher information technology costs.

Our general and administrative expenses in 2009 decreased $0.3 million from those in 2008. Before capitalization, our general and administrative costs decreased by $0.6 million. The following were the primary reasons for the decrease in general and administrative costs:

- total compensation expense decreased by $0.3 million from 2008 to 2009 due to lower levels of employee salaries and bonuses associated with our cost cutting measures implemented in April 2009; and

- office expenses decreased by $0.3 million from 2008 to 2009 due to our cost containment measures.

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

	Year Ended December 31,				
	2010	% Change	2009	% Change	2008
	(In thousands, except per unit measurements which are based on sales volumes)				
Depletion of crude oil and natural gas properties	$ 58,195	82%	$ 32,054	(40%)	$ 53,498
Depletion of crude oil and natural gas properties (per Boe)	$ 19.75	11%	$ 17.85	(36%)	$ 28.02

Our depletion expense for 2010 was $26.1 million higher than 2009. An increase in production volumes in 2010 increased depletion expense by approximately $20.5 million and our higher depletion rate increased depletion expense $5.6 million.

Our depletion expense for 2009 was $21.4 million lower than 2008. A decrease in production volumes in 2009 lowered depletion expense by approximately $3.2 million, while a decrease in our depletion rate decreased depletion expense $18.2 million. The lower depletion rate was due to our fourth quarter 2008 and first quarter 2009 ceiling test writedowns.

Impairment of crude oil and natural gas properties. We use the full cost method of accounting for crude oil and gas properties. Under this method, all acquisition, exploration and development costs, including certain payroll, asset retirement costs, other internal costs, and interest incurred for the purpose of finding crude oil and natural gas reserves, are capitalized. Internal costs and interest capitalized are directly attributable to acquisition, exploration and development activities and do not include costs related to production, general corporate overhead or similar activities.

Capitalized costs of crude oil and natural gas properties, net of accumulated amortization, are limited to the present value (10% per annum discount rate) of estimated future net cash flow from proved crude oil and natural gas reserves, based on the average of crude oil and natural gas prices in effect at the beginning of each month in the twelve month period prior to the end of the reporting period; plus the cost of properties not being amortized, if any; plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less related income tax effects. If net capitalized costs of crude oil and gas properties exceed this ceiling amount, we are subject to a ceiling test writedown to the extent of such excess. A ceiling test writedown is a non-cash charge to earnings and reduces stockholders' equity in the period of occurrence.

The risk that we will experience a ceiling test writedown increases when crude oil and gas prices are depressed or if we have a substantial downward revisions in our estimated proved reserves. Prior to December 31, 2009, the ceiling test calculation was based on crude oil and natural gas prices in effect on the balance sheet date. Based on crude oil and gas prices in effect on March 31, 2009 ($3.63 per MMBtu for Henry Hub gas and $49.65 per barrel for West Texas Intermediate crude oil, adjusted for differentials), the unamortized cost of our crude oil and gas properties exceeded the ceiling limit and we recorded a $114.8 million impairment to our crude oil and gas properties. Based on crude oil and gas prices in effect on December 31, 2008 ($5.71 per MMBtu for Henry Hub gas and $44.60 per barrel for West Texas Intermediate crude oil, adjusted for differentials), the unamortized cost of our crude oil and gas properties exceeded the ceiling limit and we recorded a $237.2 million impairment to our crude oil and gas properties.

Inventory Valuation. Our $2.2 million inventory valuation loss in 2009 was attributable to the lower of cost or market writedown of oil country tubular goods (OCTG). Market prices of OCTG experienced a substantial reduction in the first quarter of 2009 associated with lower steel costs and the oversupply of OCTG due to reduced drilling activity in the United States.

Net interest expense. Interest on our Senior Notes, our Senior Credit Facility and dividends that we paid on our Series A mandatorily redeemable preferred stock represents the largest portion of our interest expense. Other costs include commitment fees that we pay on the unused portion of the borrowing base for our Senior Credit Facility. In addition, we typically pay loan and debt issuance costs when we enter into new lending agreements or amend existing agreements. When incurred, these costs are recorded as non-current assets and are then amortized over the life of the loan. We capitalize interest costs on borrowings associated with our major capital projects prior to their completion. Capitalized interest is added to the cost of the underlying assets and is amortized over the lives of the assets.

	Year Ended December 31,				
	2010	**% Change**	**2009**	**% Change**	**2008**
	(In thousands)				
Interest on Senior Notes	$ 18,240	18%	$ 15,400	0%	$ 15,401
Interest on Senior Credit Facility	26	(99%)	3,375	72%	1,960
Commitment fees	636	226%	195	(24%)	256
Dividend on mandatorily redeemable preferred stock	269	(56%)	606	0%	608
Amortization of deferred loan and debt issuance cost	1,939	26%	1,538	49%	1,032
Other general interest expense	108	260%	30	NM	—
Capitalized interest expense	(9,770)	107%	(4,713)	(1%)	(4,762)
Net interest expense	$ 11,448	(30%)	$ 16,431	13%	$ 14,495
Weighted average debt outstanding	$ 201,447	(27%)	$ 274,211	25%	$ 220,116
Average interest rate on outstanding indebtedness(a)	9.57%		7.15%		8.28%

(a) Calculated as the sum of the interest on our outstanding indebtedness, commitment fees that we pay on our unused borrowing capacity and the dividend on our mandatorily redeemable preferred stock divided by the weighted average debt and preferred stock outstanding for the period.

Our net interest expense for 2010 was $5.0 million lower than that in 2009 primarily due to a $5.1 million increase in capitalized interest expense associated with our higher level of activity in the Williston Basin. Interest expense also decreased $3.3 million due to lower levels of debt outstanding on our Senior Credit Facility subsequent to its repayment in October 2009 in conjunction with our common stock offering. These decreases were partially offset by a $2.8 million increase in interest expense associate with the September 2010 issuance of our $300 million Senior Notes due 2018.

Our net interest expense for 2009 was $1.9 million higher than that in 2008 primarily due to a $1.4 million increase in interest expense associated with higher levels of outstanding debt on our Senior Credit Facility and a $0.5 million increase in origination fees also associated with our Senior Credit Facility.

Loss on early redemption of Senior Notes. In September 2010, we issued $300 million in Senior Notes due 2018 which funded the tender offer for and redemption of our 9 5/8% Senior Notes due in 2014. As a result of the redemption process, we incurred a loss on the Senior Notes due in 2014.

Other income (expense). Other income (expense) included:

	Year Ended December 31,				
	2010	**% Change**	**2009**	**% Change**	**2008**
			(In thousands)		
Other:					
Gain (loss) on sale of inventory or assets	831	105%	405	NM	—
Other income (loss)	4,263	274%	1,139	115%	530
Total other income (loss)	$ 5,094	230%	$ 1,544	191%	$ 530

Other income increased in 2010 as a result of higher levels of field general equipment income in the Williston Basin, which was driven by accelerated development in the basin.

Income taxes. We utilize the asset and liability approach to measure deferred tax assets and liabilities based on temporary differences existing at each balance sheet date using currently enacted tax rates in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 740 "Income Taxes" (FASB ASC 740). Under FASB ASC 740, deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. Deferred tax assets and liabilities are adjusted for the effects of changes in tax laws and rates on the date of enactment.

In 2010, we recognized a current year net deferred tax expense of $1.1 million. The $1.1 million in tax expense was mainly attributable to the state of North Dakota's deferred tax expense. The primary reasons for the difference between our effective tax rate of 2.5% and the federal statutory rate of 35% were decreases in our valuation allowances on federal and state net operating losses and our inability to deduct dividends and certain portions of our non-cash stock compensation expense for federal tax purposes.

In 2009, we recognized a current year net deferred tax benefit of $233,000. The $233,000 tax benefit was mainly due to miscellaneous state tax benefits. The primary reasons for the difference between our effective tax rate of 0.2% and the federal statutory rate of 35% were increases in our valuation allowances on federal and state net operating losses and our inability to deduct dividends and certain portions of our non-cash stock compensation expense for federal tax purposes.

In 2008, we recognized a current year net deferred federal tax benefit of $40.8 million. The $40.8 million tax benefit was due to a $222 million decrease in pre-tax income, which primarily resulted from the ceiling test writedown of $237.2 million. We also recognized a current year net deferred state tax benefit of $2 million, which consisted of the Margin Tax and other state tax benefits. The primary reasons for the difference between our effective tax rate of 20.8% and the federal statutory rate of 35% were increases in our valuation allowances on federal and state net operating losses and our inability to deduct dividends and certain portions of our non-cash stock compensation expense for federal tax purposes.

Liquidity and Capital Resources

Sources of Capital

In 2011, we intend to fund our capital expenditure program and contractual commitments with cash, cash equivalents and short term investments on hand as of year-end 2010, cash flows from operations, reimbursements of prior land and seismic costs by third parties who participate in our projects, the potential sale of interests in projects and properties, availability under our Senior Credit Facility or alternative financing sources.

Senior Notes

As of December 31, 2010, we had outstanding $300 million of 8 3/4% Senior Notes due 2018, which were issued in September 2010. In connection with the issuance of the 8 3/4% Senior Notes, we tendered for and purchased or redeemed $160 million of our 9 5/8% Senior Notes due 2014 in September and October 2010.

Our 8 3/4% Senior Notes are fully and unconditionally guaranteed by us, and our wholly-owned subsidiaries, Brigham, Inc. and Brigham Oil & Gas, L.P. Beginning April 2011, we will pay 8 3/4% interest on the $300 million outstanding. Future interest payments are due semi-annually in arrears in October and April of each year.

The 8 3/4% Senior Notes are our unsecured senior obligations, and:

- rank equally in right of payment with all our existing and future senior indebtedness;
- rank senior to all of our future subordinated indebtedness; and
- are effectively junior in right of payment to all of our and our guarantors' existing and future secured indebtedness, including debt of our Senior Credit Facility.

The Indenture governing the 8 3/4% Senior Notes contains customary events of default. Upon the occurrence of certain events of default, the trustee or the holders of the 8 3/4% Senior Notes may declare all outstanding 8 3/4% Senior Notes to be due and payable immediately.

Additionally, the Indenture governing the 8 3/4% Senior Notes contains customary restrictions and covenants which could potentially limit our flexibility to manage and fund our business. We were in compliance with all covenants associated with the 8 3/4% Senior Notes as of December 31, 2010.

Senior Credit Facility

As of December 31, 2010, our Senior Credit Facility provided for revolving credit borrowings up to $200 million and had a borrowing base of $110 million. Subsequent to December 31, 2010, we entered into our Fifth Amended and Restated Credit Facility in February 2011, which provides for revolving credit borrowings up to $600 million, a current borrowing base of $325 million and a five year maturity. As of December 31, 2010 and as of the date of the filing of this report, we had no amounts outstanding under our Senior Credit Facility.

The borrowing base under the new Senior Credit Facility will be redetermined at least semi-annually and the amount of borrowing capacity available to us under the new Senior Credit Facility could fluctuate. In the event that the borrowing base is adjusted below the amount that we have borrowed, our access to further borrowings will be reduced, and we may not have the resources necessary to pay off the borrowing base deficiency and carry out our planned spending for exploration and development activities. See "Item 1A — Risk Factors — Availability under our Senior Credit Facility is based on a borrowing base which is subject to redetermination by our lenders. If our borrowing base is reduced, we may be required to repay amounts outstanding under our Senior Credit Facility."

Borrowings under our new Senior Credit Facility bear interest at a base rate or a Eurodollar rate, at our election, plus in each case an applicable margin. These margins are reset quarterly and are subject to increase if the total amount borrowed under our new Senior Credit Facility reaches certain percentages of the available borrowing base, as shown below:

Percent of Borrowing Base Utilized	Eurodollar Rate Advances	Base Rate Advances(1)	Commitment Fee
< 50%	2.00%	1.00%	0.50%
≥ 50%	2.25%	1.25%	0.50%
≥ 75%	2.50%	1.50%	0.50%
≥ 90%	2.75%	1.75%	0.50%

(1) Base Rate means for any day a fluctuating rate per annum equal to the highest of the following: (a) the Federal Funds Rate plus 1/2 of 1%, (b) the Eurodollar Rate with respect to Interest Periods of one month determined as of approximately 11:00 a.m. (London time) on such day plus 1.00% and (c) the rate of interest in effect for such day as publicly announced from time to time by Bank of America as its "prime rate." The "prime rate" is a rate set by Bank of America based upon various factors including Bank of America's costs and desired return, general economic conditions and other factors, and is used as a reference point for pricing some loans, which may be priced at, above, or below such announced rate. Any change in such rate announced by Bank of America shall take effect at the opening of business on the day specified in the public announcement of such change.

Our new Senior Credit Facility also contains customary restrictions and covenants. Should we be unable to comply with these or other covenants, our senior lenders may be unwilling to waive compliance or amend the covenants and our liquidity may be adversely affected. Pursuant to our Senior Credit Facility, our current ratio must be at least 1.0 to 1 and net leverage ratio must not be greater than 4.00 to 1.

Mandatorily Redeemable Preferred Stock

In June 2010, we exercised our option to redeem all of our Series A mandatorily redeemable preferred stock at 101% of the stated value per share, which was held by DLJ Merchant Banking Partners III, L.P. and affiliated funds, which are managed by affiliates of Credit Suisse Securities (USA), LLC.

Off Balance Sheet Arrangements

We currently have operating leases, which are considered off balance sheet arrangements. We do not currently have any other off balance sheet arrangements or other such unrecorded obligations, and we have not guaranteed the debt of any other party.

Analysis of Changes In Cash and Cash Equivalents

The table below summarizes our sources and uses of cash during 2010, 2009 and 2008.

	Year Ended December 31,				
	2010	% Change	2009	% Change	2008
			(In thousands)		
Net income	$ 42,896	NM	$ (122,992)	24%	$ (162,247)
Non-cash charges	90,735	(43%)	159,132	(35%)	245,545
Changes in working capital and other items	10,889	(30%)	15,610	NM	(13,668)
Cash flows provided by operating activities	$ 144,520	179%	$ 51,750	(26%)	$ 69,630
Cash flows used by investing activities	(556,211)	238%	(164,620)	(8%)	(179,866)
Cash flows provided (used) by financing activities	394,653	247%	113,608	(17%)	136,416
Net increase (decrease) in cash and cash equivalents	$ (17,038)	NM	$ 738	(97%)	$ 26,180

Analysis of net cash provided by operating activities

Net cash provided by operating activities for 2010 was $92.8 million higher than 2009. The following are the primary reasons for the increase:

- higher crude oil volumes, which were partially offset by lower natural gas volumes, increased operating cash flow by $69.9 million;
- higher oil equivalent sales prices increased operating cash flow by $41.2 million;
- higher production taxes decreased operating cash flow by $12.2 million;
- lower realized hedge settlements decreased operating cash flow by $6.3 million;
- the change in working capital decreased operating cash flow by $4.7 million;
- higher lease operating costs decreased operating cash flow by $4.0 million; and
- higher general and administrative expense reduced operating cash flow by $3.7 million.

Net cash provided by operating activities for 2009 was $17.9 million lower than 2008. The following are the primary reasons for the decrease:

- a 42% decrease in sales prices of crude oil and natural gas decreased operating cash flow by $58.5 million;
- higher lease operating costs decreased operating cash flow by $2.3 million;
- the change in working capital increased operating cash flow by $29.3 million;
- higher realized hedge settlements increased operating cash flow by $13.0 million; and
- higher crude oil volumes partially offset by lower natural gas volumes decreased revenue by $1.6 million.

Working Capital

Working capital is the amount by which current assets exceed current liabilities. At the end of 2010, as a result of our April 2010 equity offering and our September 2010 Senior Notes offering we had both cash on hand and short term investments recorded on our balance sheet. This resulted in a working capital surplus at the end of 2010. At year-end 2009, we also had a working capital surplus as a result of our May and October 2009 equity offerings. At year-end 2008, we also had a working capital surplus as we had fully drawn our credit facility and placed the associated cash on deposit.

Our working capital surplus at December 31, 2010, December 31, 2009 and December 31, 2008 was $184.3 million, $90.7 million and $30.3 million, respectively. Our working capital surplus at December 31, 2010 and December 31, 2009 included a current asset of $224.0 million and $80.1 million, respectively, related to short term investments.

Analysis of changes in cash flows used by investing activities

Net cash used by investing activities increased by $391.6 million from 2009 to 2010. The primary driver for the increase was a $375.0 million increase in capital expenditures for crude oil and natural gas activities due to higher levels of drilling activity, lease acquisition, and support infrastructure in the Williston Basin. Net cash used in investing activities also increased $63.8 million due to the change in short term investments and $12.8 million due to the change in inventory. These increases were partially offset by a $49.9 million decrease in cash used associated with our increase in accrued drilling costs and $17.7 million in asset sale proceeds which also decreased cash used during the period.

Net cash used by investing activities decreased by $15.2 million from 2008 to 2009. The primary drivers for the decrease were a $78.0 million decrease in our drilling capital expenditures and a $34.0 million decrease in our land and seismic capital expenditures. These decreases were offset by a $80.1 million increase in cash used associated with our increased level of short term investments and a $9.2 million increase in cash used associated with the change in our accrued drilling costs.

The following is a detailed breakout of our net cash used in investing activities for 2010, 2009 and 2008 in thousands.

	2010	% Change	2009	% Change	2008
Capital expenditures for crude oil and natural gas activities:					
Drilling	$ 280,080	381%	$ 58,209	(57%)	$ 136,248
Support infrastructure (a)	33,226	NM	—	0%	—
Land	112,153	6,269%	1,761	(95%)	35,796
Capitalized cost	21,470	73%	12,432	(3%)	12,852
Capitalized asset retirement obligation	814	149%	327	(21%)	412
Total	$ 447,743	516%	$ 72,729	(61%)	$ 185,308
Reconciling Items:					
Asset sale proceeds including ARO reduction liability	$ (17,698)	NM	$ —	0%	$ —
Change in short term investments	143,898	80%	80,093	NM	—
Change in other property and equipment (b)	6,235	280%	1,642	249%	470
Change in accrued drilling costs	(45,569)	NM	4,270	NM	(4,927)
Change in drilling advances paid	794	NM	—	0%	—
Change in inventory	20,709	163%	7,881	NM	—
Other	99	NM	(1,995)	103%	(985)
Total Reconciling Items	108,468	18%	91,891	NM	(5,442)
Net cash used in investing activities	$ 556,211	238%	$ 164,620	(8%)	$ 179,866

(a) Support infrastructure costs are recorded on our balance sheet in Other Property and Equipment.

(b) Excludes approximately $33.2 million in support infrastructure costs, which are included in capital expenditures for crude oil and natural gas activities above.

Analysis of changes in cash flows from financing activities

Over the three year period ended December 31, 2010, we have entered into various financing transactions with the intent of increasing our liquidity so that we could fund our capital expenditures for the exploration and development of crude oil and natural gas properties.

Our net cash provided by financing activities in 2010 was $281.0 million higher than in 2009. In 2010, we received net proceeds of $277.5 million from our April common stock offering and net proceeds of $118 million from our September 8 3/4% Senior Notes offering after both tendering for and redeeming our 9 5/8 Senior Notes due 2014.

Our net cash provided by financing activities in 2009 was $22.8 million lower than in 2008. In 2009, we raised $261.7 million in net proceeds from the sale of common stock and repaid the $145.0 million outstanding under our Senior Credit Facility thereby generating net cash provided by financing activities of $113.6 million. In 2008, we generated $135 million in financing proceeds via borrowings under our Senior Credit Facility.

Common Stock Transactions

Our net proceeds from the sale of common stock and employee stock option exercises were $18.5 million higher in 2010 than they were in 2009 due to our April 2010 equity offering. This compares to net proceeds that were $260.9 million higher in 2009 than in 2008 due to our May and October 2009 equity offerings.

The following is a list of common stock transactions that occurred in 2010, 2009 and 2008.

	Shares Issued	Net Proceeds (in thousands)
2010 common stock transactions:		
April 2010 common stock offering	16,100,000	$ 277,547
Exercise of employee stock options	741,037	$ 3,884
2009 common stock transactions:		
May 2009 common stock offering	36,292,117	$ 93,407
October 2009 common stock offering	16,837,523	$ 168,318
Exercise of employee stock options	256,314	$ 1,219
2008 common stock transactions:		
Exercise of employee stock options	385,715	$ 2,066

Critical Accounting Policies

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

Use of Estimates

The preparation of financial statements in accordance with GAAP in the United States of America requires us to make estimates and assumptions that affect our reported assets, liabilities, revenues, expenses, and some narrative disclosures. Our estimates of our proved crude oil and natural gas reserves, future development costs, production expense, revenue and deferred income taxes are the most critical to our financial statements.

Crude oil and Natural Gas Reserves

The determination of depreciation, depletion and amortization expense as well as impairments that are recognized on our crude oil and natural gas properties are highly dependent on the estimates of the proved crude oil and natural gas reserves attributable to our properties. Our estimate of proved reserves is based on the quantities of crude oil and natural gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in the future years from known reservoirs under existing economic and operating conditions. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. For example, we must estimate the amount and timing of future operating costs, severance taxes and development costs, all of which may in fact vary considerably from actual results. In addition, as the prices of crude oil and natural gas and cost levels change from year to year, the economics of producing our reserves may change and therefore the estimate of proved reserves may also change. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves.

The information regarding present value of the future net cash flows attributable to our proved crude oil and natural gas reserves are estimates only and should not be construed as the current market value of the estimated crude oil and natural gas reserves attributable to our properties. Thus, such information includes revisions of certain reserve estimates attributable to our properties included in the prior year's estimates. These revisions reflect additional information from subsequent activities, production history of the properties involved and any adjustments in the projected economic life of such properties resulting from changes in crude oil and natural gas prices. Any future downward revisions could adversely affect our financial condition, our borrowing ability, our future prospects and the value of our common stock.

The estimates of our proved crude oil and natural gas reserves used in the preparation of our consolidated financial statements were prepared by CGA, our registered independent petroleum consultants, and were prepared in accordance with the rules promulgated by the SEC.

Crude Oil and Natural Gas Property

The method of accounting we use to account for our crude oil and natural gas investments determines what costs are capitalized and how these costs are ultimately matched with revenues and expensed.

We utilize the full cost method of accounting to account for our crude oil and natural gas investments instead of the successful efforts method because we believe it more accurately reflects the underlying economics of our programs to explore and develop crude oil and natural gas reserves. The full cost method embraces the concept that dry holes and other expenditures that fail to add reserves are intrinsic to the oil and natural gas exploration business. Thus, under the full cost method, all costs incurred in connection with the acquisition, development and exploration of crude oil and natural gas reserves are capitalized. These capitalized amounts include the costs of unproved properties, internal costs directly related to acquisitions, development and exploration activities, asset retirement costs, geological and geophysical costs and capitalized interest. Although some of these costs will ultimately result in no additional reserves, they are part of a program from which we expect the benefits of successful wells to more than offset the costs of any unsuccessful ones. The full cost method differs from the successful efforts method of accounting for crude oil and natural gas investments. The primary difference between these two methods is the treatment of exploratory dry hole costs. These costs are generally expensed under the successful efforts method when it is determined that measurable reserves do not exist. Geological and geophysical costs are also expensed under the successful efforts method. Under the full cost method, both dry hole costs and geological and geophysical costs are initially capitalized and classified as unevaluated properties pending determination of proved reserves. If no proved reserves are discovered, these costs are then amortized with all the costs in the full cost pool.

Capitalized amounts except unevaluated costs are depleted using the units of production method. The depletion expense per unit of production is the ratio of the sum of our unamortized historical costs and estimated future development costs to our proved reserve volumes. Estimation of hydrocarbon reserves relies on professional judgment and use of factors that cannot be precisely determined. Subsequent reserve estimates materially different from those reported would change the depletion expense recognized during the future reporting periods. For the quarter ended December 31, 2010, our average depletion expense per unit of production was $18.64 per Boe. A 10% decrease in our estimated net proved reserves at December 31, 2010 would result in a $2.04 per Boe increase in our per unit depletion expense and a $3.5 million decrease in our pre-tax net income.

To the extent the capitalized costs in our full cost pool (net of depreciation, depletion and amortization and related deferred taxes) exceed the sum of the present value (using a 10% discount rate and based on period-end crude oil and natural gas prices) of the estimated future net cash flows from our proved crude oil and natural gas reserves and the capitalized cost associated with our unproved properties, we would have a capitalized ceiling impairment. Such costs would be charged to operations as a reduction of the carrying value of crude oil and natural gas properties. The risk that we will be required to write down the carrying value of our crude oil and natural gas properties increases when crude oil and natural gas prices are depressed, even if the low prices are temporary. In addition, capitalized ceiling impairment charges may occur if we experience poor drilling results or estimations of our proved reserves are substantially reduced. A capitalized ceiling impairment is a reduction in earnings that does not impact cash flows, but does impact operating income and stockholders' equity. Once recognized, a capitalized ceiling impairment charge to crude oil and natural gas properties cannot be reversed at a later date. The risk that we will experience a ceiling test writedown increases when crude oil and gas prices are depressed or if we have substantial downward revisions in our estimated proved reserves.

Based on crude oil and gas prices in effect on March 31, 2009 ($3.63 per MMBtu for Henry Hub gas and $49.65 per barrel for West Texas Intermediate crude oil, adjusted for differentials), the unamortized cost of our crude oil and gas properties exceeded the ceiling limit and we recorded a $114.8 million ($71.9 million after tax) impairment to our crude oil and gas properties. Also, at December 31, 2008, the unamortized cost of our crude oil and gas properties exceeded the ceiling limit based on crude oil and gas prices in effect ($5.71 per MMBtu for Henry Hub gas and $44.60 per barrel for West Texas Intermediate crude oil, adjusted for differentials). Therefore, we recorded a $237.2 million ($148.6 million after tax) impairment to our crude oil and gas properties at December 31, 2008.

No assurance can be given that we will not experience a capitalized ceiling impairment charge in future periods. In addition, capitalized ceiling impairment charges may occur if estimates of proved hydrocarbon reserves are substantially reduced or estimates of future development costs increase significantly. See "Item 1A. Risk Factors — Exploratory drilling is a speculative activity that may not result in commercially productive reserves and may require expenditures in excess of budgeted amounts," "Item 1A. Risk Factors — We need to replace our reserves at a faster rate than companies whose reserves have longer production lives. Our failure to replace our reserves would result in decreasing reserves and production over time" and "Item 1A. Risk Factors — Lower crude oil and natural gas prices may cause us to record ceiling limitation writedowns, which would reduce our stockholders' equity." Additionally, the modernization of SEC oil and gas reporting rules eliminated the ability to use subsequent pricing in assessing the need for a ceiling limitation writedown. This could cause us to record a ceiling limitation writedown that would not be required if subsequent pricing were used.

Asset Retirement Obligations

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

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

Income Taxes

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

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

We have a significant net deferred tax asset associated with net operating loss carryforwards (NOLs). Based on estimates of the reversal of our temporary differences, it is more likely than not that we will not use all of these NOLs to offset current tax liabilities in future years. We have, therefore, established a valuation allowance on the portion of the NOLs that may expire unused. Our NOLs are more fully described in "Item 8. Financial Statements and Supplementary Data — Note 8. Income Taxes."

Revenue Recognition

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

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

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

Settlements for hydrocarbon sales can occur up to two months after the end of the month in which the crude oil, natural gas or other hydrocarbon products were produced. We estimate and accrue for the value of these sales using information available to us at the time our financial statements are generated. Differences are reflected in the accounting period that payments are received from the purchaser.

Derivative Instruments and Hedging Activities

We use derivative instruments to manage our market risks associated with fluctuations in crude oil and natural gas prices. We enter into derivative contracts, including costless collars, swaps, ceilings and floors, which upon settlement require payments to (or receipts from) counterparties based on the difference between a fixed price and a variable price for fixed quantities of crude oil and natural gas without exchanging underlying volumes. The notional amounts of these financial instruments are based on expected production from existing and future wells.

All derivatives are accounted for in accordance with FASB ASC 815 and carried at fair value on the balance sheet. We utilize the mark-to-market methodology to account for our hedges. Mark-to-market accounting requires that both derivative settlements and unrealized gains (losses) are recorded on the consolidated statement of operations. We have elected to include all derivative settlement and unrealized gains (losses) within revenues.

New Accounting Pronouncements

On December 31, 2008, the SEC published the final rules and interpretations updating its oil and gas reporting requirements. Many of the revisions are updates to definitions in the existing oil and gas rules to make them consistent with the petroleum resource management system, which is a widely accepted standard for the management of petroleum resources that was developed by several industry organizations. Key revisions include the ability to include nontraditional resources in reserves, the use of new technology for determining reserves, permitting disclosure of probable and possible reserves, and changes to the pricing used to determine reserves in that companies must use a 12-month average price. The average is calculated using the first-day-of-the-month price for each of the 12 months that make up the reporting period. The SEC required companies to comply with the amended disclosure requirements for registration statements filed after January 1, 2010, and for annual reports for fiscal years ending on or after December 15, 2009. Early adoption was not permitted. Financial Accounting Standards Board Accounting Standards Codification Topic 932 "Extractive Activities — Oil and Gas" (FASB ASC 932) provides guidance for oil and natural gas reserve related disclosures in the financial statements. Adoption of the new requirements did not have a material impact on Brigham's financial statements.

Other Matters

Commodity Prices

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

The prices we receive for our crude oil production are based on global market conditions. Our average pre-hedged sales price for crude oil in 2010 was $71.08 per barrel, which was 30% higher than the prices we received in 2009. Significant factors that will impact 2011 crude oil prices include the pace at which the domestic and global economies continue to recover, the extent to which members of the Organization of Petroleum Exporting Countries and other crude oil exporting nations are able to manage crude oil supply through export quotas and geopolitical developments in African and Middle East Countries.

Natural gas prices are primarily driven by North American market forces. However, global LNG shipments can impact North American markets to the extent cargoes are diverted from Asia or Europe to North America. Factors that can affect the price of natural gas are changes in market demands, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. Over the past three years, natural gas prices have been volatile. Our average pre-hedged sales price for natural gas in 2010 was $5.23 per Mcf, which was 30% higher than the price we received in 2009. Natural gas prices in 2011 will be dependent upon many factors including the balance between North American supply and demand.

Derivative Instruments

Our results of operations and operating cash flow are impacted by changes in market prices for crude oil and gas. We believe the use of derivative instruments, although not free of risk, allows us to reduce our exposure to crude oil and natural gas sales price fluctuations and thereby achieve a more predictable cash flow. While the use of derivative instruments limits the downside risk of adverse price movements, their use may also limit future revenues from favorable price movements. Moreover, our derivative contracts generally do not apply to all of our production and thus provide only partial price protection against declines in commodity prices. We expect that the amount of our derivative contracts will vary from time to time. See "Item 1A. Risk Factors — Our hedging activities may prevent us from benefiting from price increases and may expose us to other risks" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk — Derivative Instruments and Hedging Activities."

Effects of Inflation and Changes in Prices

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

Environmental and Other Regulatory Matters

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

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

Management Opinion Concerning Derivative Instruments

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

Fair Value of Derivative Contracts

We use the mark-to-market accounting methodology to account for our hedges. At the end of each quarter, our derivatives are marked-to-market to reflect the current fair value and both derivative settlements and unrealized gains (losses) are recorded on the consolidated statement of operations. We include all derivative settlements and unrealized gains (losses) within revenue.

The fair values of our derivative contracts are determined based on counterparties' estimates and valuation models. We did not change our valuation methodology during the year ended December 31, 2010. The following table reconciles the changes that occurred in the fair values of our open derivative contracts during 2010.

	Fair Value of Undesignated Derivative Contracts
Estimated fair value of open contracts at December 31, 2009	$ (1,975)
Changes in fair values of derivative contracts:	
Natural gas collars	$ 4,210
Crude oil collars	(14,276)
Settlements of derivative contracts that were open at December 31, 2009:	
Natural gas collars	$ (3,578)
Crude oil collars	468
Estimated fair value of open contracts at December 31, 2010	$ (15,151)

Derivative Instruments and Hedging Activities

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

While the use of derivative instruments limits the downside risk of adverse price movements, their use may also limit future revenues from favorable price movements. Moreover, our derivative contracts generally do not apply to all of our production and thus provide only partial price protection against declines in commodity prices. We expect that the amount of our derivative contracts will vary from time to time.

During 2010, we were party to crude oil costless collars, crude oil swaps, crude oil puts, natural gas costless collars, natural gas three-way costless collars, and natural gas swaps. See "Item 8. Financial Statements and Supplementary Data — Note 11. Derivative Instruments and Hedging Activities" for additional information regarding our derivative contracts.

We use costless collars to establish floor (purchased put option) and ceiling prices (written call option) on our anticipated future crude oil and natural gas production. We neither receive nor pay net premiums when we enter into these option arrangements. These contracts are settled monthly. When the settlement price for a period is above the ceiling price (written call option), we pay our counterparty. When the settlement price for a period is below the floor price (purchased put option), our counterparty is required to pay us. All hedges are accounted for using mark-to-market accounting.

A three-way costless collar consists of a costless collar (purchased put option and written call option) plus a put (written put) sold by us with a price below the floor price (purchased put option) of the costless collar. We neither receive nor pay net premiums when we enter into these option arrangements. These contracts are settled monthly. The written put requires us to make a payment to our counterparty if the settlement price for a period is below the written put price. Combining the costless collar (purchased put option and written call option) with the written put results in us being entitled to a net payment equal to the difference between the floor price (purchased put option) of the costless collar and the written put price if the settlement price is equal to or less than the written put price. If the settlement price is greater than the written put price, the result is the same as it would have been with a costless collar. This strategy enables us to increase the floor and the ceiling price of the collar beyond the range of a traditional costless collar while offsetting the associated cost with the sale of the written put. All hedges are accounted for using mark-to-market accounting.

We also use put options to establish floor prices (purchased put option) on our anticipated future crude oil production. We pay an initial premium when we enter into these option arrangements. These contracts are settled monthly. When the settlement price for a period is below the floor price (purchased put option), our counterparty is required to pay us. All hedges are accounted for using mark-to-market accounting.

We use swaps to fix the sales price for our anticipated future natural gas production. Upon settlement, we receive a fixed price for the hedged commodity and pay our counterparty a floating market price, as defined in each instrument. These instruments are settled monthly. When the floating price exceeds the fixed price for a contract month, we pay our counterparty. When the fixed price exceeds the floating price, our counterparty is required to make a payment to us. All hedges are accounted for using mark-to-market accounting.

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

The following table reflects our open derivative contracts at December 31, 2010, the associated volumes and the corresponding weighted average NYMEX reference price.

Settlement Period	Crude Oil (Bbls)	Purchased Put (Nymex)	Written Call (Nymex)
Crude Oil Costless Collars			
01/01/11 – 12/31/11	84,000	$ 65.00	$ 88.25
01/01/11 – 12/31/11	60,000	$ 60.00	$ 97.25
01/01/11 – 12/31/11	60,000	$ 65.00	$ 108.00
01/01/11 – 06/30/11	18,000	$ 65.00	$ 97.50
01/01/11 – 12/31/11	48,000	$ 70.00	$ 106.80
01/01/11 – 12/31/11	48,000	$ 75.00	$ 102.60
07/01/11 – 12/31/11	12,000	$ 75.00	$ 103.00
01/01/11 – 06/30/11	24,000	$ 70.00	$ 92.50
07/01/11 – 09/30/11	9,000	$ 70.00	$ 95.00
10/01/11 – 12/31/11	6,000	$ 70.00	$ 96.35
01/01/11 – 02/28/11	10,000	$ 70.00	$ 92.00
01/01/11 – 07/31/11	21,000	$ 70.00	$ 94.80
01/01/11 – 03/31/11	9,000	$ 75.00	$ 93.50
07/01/11 – 12/31/11	12,000	$ 75.00	$ 95.15
01/01/11 – 12/31/11	36,000	$ 75.00	$ 104.30
01/01/12 – 06/30/12	60,000	$ 75.00	$ 106.90
01/01/11 – 02/28/11	8,000	$ 75.00	$ 103.50
03/01/11 – 04/30/11	16,000	$ 75.00	$ 104.50
01/01/11 – 12/31/11	36,000	$ 65.00	$ 100.00
01/01/11 – 07/31/12	289,000	$ 65.00	$ 97.20
01/01/11 – 07/31/12	289,000	$ 65.00	$ 98.55
01/01/11 – 07/31/12	289,000	$ 65.00	$ 100.00
01/01/11 – 07/31/12	289,000	$ 65.00	$ 100.40
03/01/11 – 08/31/11	46,000	$ 65.00	$ 94.80
09/01/11 – 12/31/11	61,000	$ 65.00	$ 97.40
01/01/12 – 06/30/12	182,000	$ 65.00	$ 99.25

Settlement Period	Crude Oil (Bbls)	Purchased Put (Nymex)	Written Call (Nymex)
09/01/11 – 12/31/11	61,000	$ 65.00	$ 99.00
03/01/11 – 08/31/11	46,000	$ 65.00	$ 96.75
01/01/12 – 06/30/12	91,000	$ 65.00	$ 101.00
01/01/12 – 06/30/12	182,000	$ 65.00	$ 100.75
01/01/12 – 06/30/12	91,000	$ 65.00	$ 102.75
07/01/12 – 07/31/12	62,000	$ 65.00	$ 102.25
05/01/11 – 12/31/11	122,500	$ 65.00	$ 100.00
07/01/12 – 07/31/12	31,000	$ 65.00	$ 105.25
05/01/11 – 12/31/11	122,500	$ 65.00	$ 106.50
01/01/11 – 02/28/11	29,500	$ 65.00	$ 98.75
01/01/11 – 12/31/11	182,500	$ 65.00	$ 100.00
01/01/12 – 06/30/12	136,500	$ 65.00	$ 107.25
07/01/12 – 09/30/12	92,000	$ 65.00	$ 109.40
08/01/12 – 09/30/12	61,000	$ 65.00	$ 110.25
08/01/12 – 09/30/12	61,000	$ 65.00	$ 112.00
10/01/12 – 10/31/12	62,000	$ 65.00	$ 112.65
01/01/12 – 07/31/12	106,500	$ 65.00	$ 110.00
01/01/11 – 06/30/11*	90,500	$ 65.00	$ 95.00
01/01/11 – 06/30/11*	90,500	$ 65.00	$ 97.50
08/01/12 – 10/31/12	92,000	$ 70.00	$ 110.90
10/01/12 – 10/31/12	31,000	$ 70.00	$ 110.90
08/01/12 – 10/31/12	92,000	$ 70.00	$ 106.50
11/01/12 – 12/31/12	122,000	$ 70.00	$ 107.70
11/01/12 – 12/31/12	122,000	$ 70.00	$ 110.00

* Crude oil collar was completed in two phases. First, the put option (floor) was purchased. Subsequently, the call option (ceiling) was sold thereby converting the position into a collar.

Settlement Period	Crude Oil (Bbls)	Purchased Put (Nymex)
Crude Oil Floors		
01/01/12 – 06/30/12	91,000	$ 65.00
01/01/12 – 06/30/12	91,000	$ 65.00
01/01/12 – 06/30/12	45,500	$ 65.00
01/01/12 – 06/30/12	45,500	$ 65.00

Settlement Period	Natural Gas (MMbtu)	Purchased Put (Nymex)	Written Call (Nymex)
Natural Gas Costless Collars			
01/01/11 – 03/31/11	120,000	$ 6.50	$ 8.25
01/01/11 – 03/31/11	210,000	$ 6.40	$ 7.80
01/01/11 – 12/31/11	360,000	$ 5.75	$ 7.65
01/01/11 – 12/31/11	480,000	$ 5.75	$ 7.40
04/01/11 – 12/31/11	360,000	$ 5.00	$ 6.55

The following table reflects commodity derivative contracts entered into subsequent to December 31, 2010, the associated volumes and the corresponding weighted average NYMEX reference price.

Settlement Period	Crude Oil (Bbls)	Purchased Put (Nymex)	Written Call (Nymex)
Crude oil Costless Collars			
07/01/11 – 12/31/11**	276,000	$ 65.00	$ 100.00
08/01/12 – 10/31/12	276,000	$ 75.00	$ 112.50
11/01/12 – 12/31/12	244,000	$ 75.00	$ 112.50
07/01/12 – 07/31/12	62,000	$ 75.00	$ 114.00
01/01/13 – 02/28/13	118,000	$ 75.00	$ 113.05
01/01/13 – 03/31/13	180,000	$ 80.00	$ 120.00
03/01/13 – 03/31/13	62,000	$ 80.00	$ 120.00

Settlement Period	Crude Oil (Bbls)	Purchased Put (Nymex)
Crude Oil Floors		
07/01/12 – 12/31/12	276,000	$ 80.00

** Crude oil collar was completed in two phases. First, the put option (floor) was purchased prior to December 31, 2010. Subsequently, the call option (ceiling) was sold in January 2011 thereby converting the position into a collar.

Interest Rate Risk

At December 31, 2010, we had $300 million of long term debt, all of which was fixed rate. Our fixed rate long-term debt consists entirely of our $300 million 8 3/4% Senior Notes due 2018.

The interest rate that we pay on amounts borrowed under our Senior Credit Facility is derived from the Eurodollar rate and a margin that is applied to the Eurodollar rate. This calculation was performed using the one month Eurodollar rate on December 31, 2010, which was 0.32%. The margin that we pay is based upon the percentage of our available borrowing base that we utilize at the beginning of the quarter. At December 31, 2010, the borrowing base for our Senior Credit Facility was $110 million. Since we had no outstanding balance under our Senior Credit Facility at December 31, 2010, we were utilizing 0% of our available borrowing base. At this level of utilization, our Senior Credit Facility requires us to pay a margin of 2.50%. Our all-in interest rate that we would be required to pay on the amounts borrowed under our Senior Credit Facility would have been 2.82%. A 10% increase in the Eurodollar rate would equal approximately three basis points. Such an increase in the Eurodollar rate would change our annual interest expense by approximately $33,000, assuming amounts borrowed under our Senior Credit Facility equaled our total potential borrowing base of $110 million as of December 31, 2010. At year-end 2010, we had no amounts outstanding under our Senior Credit Facility.

Item 8. ***Financial Statements and Supplementary Data***

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

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of December 31, 2010, our management, including our principal executive officer and principal financial officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon and as of the date of the evaluation, our principal executive officer and our principal financial officer concluded that the design and operation of our disclosure controls and procedures were effective at a reasonable assurance level in that they ensure that information required to be disclosed by us in the reports that we file or submit under the Securities and Exchange Act of 1934 is (1) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and (2) accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our evaluation under the framework in *Internal Control — Integrated Framework* issued by the COSO, our management concluded that our internal control over financial reporting was effective as of December 31, 2010.

The effectiveness of our internal control over financial reporting as of December 31, 2010 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report, which is included herein.

Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting during the fourth quarter of 2010 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. *Other Information*

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

The information required by this item is incorporated by reference to the 2011 Proxy Statement, which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2010.

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

Item 11. *Executive Compensation*

The information required by this item is incorporated herein by reference to the 2011 Proxy Statement, which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2010.

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

The information required by this item is incorporated herein by reference to the 2011 Proxy Statement, which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2010. See "Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities," which sets forth certain information with respect to our equity compensation plans.

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

The information required by this item is incorporated herein by reference to the 2011 Proxy Statement, which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2010.

Item 14. *Principal Accounting Fees and Services*

The information required by this item is incorporated herein by reference to the 2011 Proxy Statement, which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2010.

PART IV

Item 15. *Exhibits, Financial Statement Schedules*

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

2. No schedules are required.

3. Exhibits:

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

GLOSSARY OF OIL AND GAS TERMS

The following are abbreviations and definitions of certain terms commonly used in the oil and gas industry and in this report. The definitions of proved developed reserves, proved reserves and proved undeveloped reserves have been abbreviated from the applicable definitions contained in Rule 4-10(a)(2-4) of Regulation S-X.

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

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

Boe. A barrel of oil equivalent is approximately six thousand cubic feet of typical natural gas.

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

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

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

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

Early Production Rate. The peak 24 hour production rate of a well, usually achieved within the first few days after being brought on line to production.

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

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

Hydraulic fracturing. A stimulation treatment routinely performed on crude oil and gas wells in low-permeability reservoirs. Specially engineered fluids are pumped at high pressure and rate into the reservoir interval to be treated, causing a vertical fracture to open. The wings of the fracture extend away from the wellbore in opposing directions according to the natural stresses within the formation.

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

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

MBoe. One thousand barrels of crude oil equivalent.

Mcf. One thousand cubic feet of natural gas.

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

Mcfe. One thousand cubic feet of natural gas equivalents.

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

MMcf. One million cubic feet of natural gas.

MMcfe. One million cubic feet of natural gas equivalents.

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

Net Production. Production that we own less royalties and production due others.

Oil. Crude oil, condensate or other liquid hydrocarbons.

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

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

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

Proved Developed Reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved Reserves. The estimated quantities of crude oil, natural gas and natural gas liquids, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved Undeveloped Reserves. Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

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 (or restart) drilling a new well.

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

Working Interest. An interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce crude 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 February 28, 2011.

BRIGHAM EXPLORATION COMPANY

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

Pursuant to the requirements of the Securities Exchange Act of 1934, the following persons on behalf of the Registrant and in the capacity indicated have signed this report below as of February 28, 2011.

/s/ BEN M. BRIGHAM Ben M. Brigham	Chief Executive Officer, President and Chairman of the Board (Principal Executive Officer)
/s/ EUGENE B. SHEPHERD, JR. Eugene B. Shepherd, Jr.	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)
/s/ DAVID T. BRIGHAM David T. Brigham	Executive Vice President — Land and Administration and Director
/s/ HAROLD D. CARTER Harold D. Carter	Director
/s/ STEPHEN C. HURLEY Stephen C. Hurley	Director
/s/ STEPHEN P. REYNOLDS Stephen P. Reynolds	Director
/s/ HOBART A. SMITH Hobart A. Smith	Director
/s/ SCOTT W. TINKER Scott W. Tinker	Director

BRIGHAM EXPLORATION COMPANY

INDEX TO FINANCIAL STATEMENTS

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Brigham Exploration Company:

We have audited the accompanying consolidated balance sheets of Brigham Exploration Company and subsidiaries (the Company) as of December 31, 2010 and 2009, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2010. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Brigham Exploration Company and subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Brigham Exploration Company's internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control — Integrated Framework,* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 1, 2011 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

(signed) KPMG LLP

Dallas, Texas
March 1, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Brigham Exploration Company:

We have audited Brigham Exploration Company's (the Company) internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, Brigham Exploration Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control — Integrated Framework,* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Brigham Exploration Company and subsidiaries as of December 31, 2010 and 2009, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2010, and our report dated March 1, 2011 expressed an unqualified opinion on those consolidated financial statements.

(signed) KPMG LLP

Dallas, Texas
March 1, 2011

BRIGHAM EXPLORATION COMPANY

CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	December 31, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 23,743	$ 40,781
Accounts receivable	70,368	21,194
Short term investments	223,991	80,093
Inventory	34,959	14,087
Other current assets	7,796	2,284
Total current assets	360,857	158,439
Oil and natural gas properties, using the full cost method of accounting		
Proved	910,114	619,920
Unproved	182,933	76,309
Accumulated depletion	(423,691)	(365,496)
	669,356	330,733
Other property and equipment, net	42,837	3,025
Deferred loan fees	9,064	5,213
Other noncurrent assets	3,287	846
Total assets	$ 1,085,401	$ 498,256
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 50,023	$ 19,251
Royalties payable	42,155	8,268
Accrued drilling costs	61,067	15,498
Participant advances received	3,037	6,949
Series A Preferred Stock, mandatorily redeemable, $.01 par value, $20 stated and redemption value, 2,250,000 shares authorized, 505,051 shares issued and outstanding at December 31, 2009	—	10,101
Derivative liabilities	9,442	2,405
Other current liabilities	10,821	5,301
Total current liabilities	176,545	67,773
Senior Notes	300,000	158,968
Deferred income taxes	1,088	—
Other noncurrent liabilities	14,498	7,232
Commitments and contingencies (Note 10)		
Stockholders' equity:		
Common stock, $.01 par value, 180 million shares authorized, 116,564,182 and 99,593,075 shares issued and 116,289,180 and 99,351,825 shares outstanding at December 31, 2010 and 2009, respectively	1,166	996
Additional paid-in capital	765,326	479,077
Treasury stock, at cost; 275,002 and 241,250 shares at December 31, 2010 and 2009, respectively	(2,657)	(2,133)
Accumulated other comprehensive income (loss)	(9)	(205)
Retained earnings (deficit)	(170,556)	(213,452)
Total stockholders' equity	593,270	264,283
Total liabilities and stockholders' equity	$ 1,085,401	$ 498,256

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

BRIGHAM EXPLORATION COMPANY

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

	Year Ended December 31,		
	2010	2009	2008
Revenues:			
Oil and natural gas sales	$ 179,279	$ 68,192	$ 125,108
Gain (loss) on derivatives, net	(10,066)	2,064	2,548
Support infrastructure	489	—	—
Other revenue	20	88	132
	169,722	70,344	127,788
Costs and expenses:			
Lease operating	18,651	14,655	12,363
Production taxes	17,313	5,098	5,374
Support infrastructure	50	—	—
General and administrative	12,943	9,243	9,557
Depletion of oil and natural gas properties	58,195	32,054	53,498
Impairment of oil and natural gas properties	—	114,781	237,180
Depreciation and amortization	1,704	812	629
Accretion of discount on asset retirement obligations	422	421	361
Loss on inventory valuation	—	2,196	—
	109,278	179,260	318,962
Operating income (loss)	60,444	(108,916)	(191,174)
Other income (expense):			
Interest income	1,198	578	191
Interest expense, net	(11,448)	(16,431)	(14,495)
Loss on early redemption of Senior Notes	(11,308)	—	—
Other income (expense)	5,094	1,544	530
	(16,464)	(14,309)	(13,774)
Income (loss) before income taxes	43,980	(123,225)	(204,948)
Income tax benefit (expense):			
Current	—	—	—
Deferred	(1,084)	233	42,701
	(1,084)	233	42,701
Net Income (loss)	$ 42,896	$ (122,992)	$ (162,247)
Net income (loss) per share available to common stockholders:			
Basic	$ 0.39	$ (1.74)	$ (3.57)
Diluted	$ 0.38	$ (1.74)	$ (3.57)
Weighted average common shares outstanding:			
Basic	111,355	70,569	45,441
Diluted	113,308	70,569	45,441

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

BRIGHAM EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In thousands)

	Common Stock Shares	Common Stock Amounts	Additional Paid In Capital	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity
Balance, December 31, 2007	45,304	$ 453	$ 207,526	$ (854)	$ 115	$ 71,787	$ 279,027
Comprehensive income (loss):							
Net income	—	—	—	—	—	(162,247)	(162,247)
Tax provisions related to cash flow hedges	—	—	—	—	61	—	61
Net (gains) losses included in net income	—	—	—	—	(176)	—	(176)
Comprehensive income							(162,362)
Issuance of common stock	—	—	—	—	—	—	—
Vesting of restricted stock	139	1	(1)	—	—	—	—
Exercise of employee stock options	386	4	2,062	—	—	—	2,066
Repurchases of common stock	—	—	—	(348)	—	—	(348)
Vesting of share-based payments	—	—	2,886	—	—	—	2,886
Balance, December 31, 2008	45,829	$ 458	$ 212,473	$ (1,202)	$ —	$ (90,460)	$ 121,269
Comprehensive income (loss):							
Net income	—	—	—	—	—	(122,992)	(122,992)
Tax provisions related to cash flow hedges	—	—	—	—	(205)	—	(205)
Net (gains) losses included in net income	—	—	—	—	—	—	—
Comprehensive income							(123,197)
Issuance of common stock	53,130	532	261,193	—	—	—	261,725
Vesting of restricted stock	378	4	(4)	—	—	—	—
Exercise of employee stock options	256	2	1,217	—	—	—	1,219
Repurchases of common stock	—	—	—	(931)	—	—	(931)
Vesting of share-based payments	—	—	4,198	—	—	—	4,198
Balance, December 31, 2009	99,593	$ 996	$ 479,077	$ (2,133)	$ (205)	$ (213,452)	$ 264,283
Comprehensive income (loss):							
Net income (loss)	—	—	—	—	—	42,896	42,896
Unrealized gains (loss) on investments	—	—	—	—	196	—	196
Tax benefits (provisions)	—	—	—	—	—	—	—
Comprehensive income (loss)							43,092
Issuance of common stock	16,100	161	277,386	—	—	—	277,547
Vesting of restricted stock	130	1	(1)	—	—	—	—
Exercise of employee stock options	741	8	3,876	—	—	—	3,884
Repurchases of common stock	—	—	—	(524)	—	—	(524)
Vesting of share-based payments	—	—	4,988	—	—	—	4,988
Balance, December 31, 2010	116,564	$ 1,166	$ 765,326	$ (2,657)	$ (9)	$ (170,556)	$ 593,270

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

BRIGHAM EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2010	2009	2008
Cash flows from operating activities:			
Net income (loss)	$ 42,896	$ (122,992)	$ (162,247)
Adjustments to reconcile net income (loss) to cash provided (used) by operating activities:			
Depletion of oil and natural gas properties	58,195	32,054	53,498
Impairment of oil and natural gas properties	—	114,781	237,180
Depreciation and amortization	1,704	812	629
Stock based compensation	2,676	2,278	1,592
Amortization of discount and deferred loan fees	2,025	1,635	1,105
Loss on early redemption of Senior Notes	11,308	—	—
Accretion of discount on asset retirement obligations	422	421	361
Market value adjustment for derivative instruments	13,175	7,313	(6,140)
Deferred income taxes	1,084	(233)	(42,701)
Provision for doubtful accounts	146	(19)	17
Other noncash items	—	90	4
Changes in working capital and other items:			
Accounts receivable	(49,320)	3,383	(9,966)
Other current assets	(4,106)	803	(6,521)
Accounts and royalties payable	64,659	6,363	2,877
Other current liabilities	1,608	4,964	500
Noncurrent assets	(1,524)	114	(330)
Noncurrent liabilities	(428)	(17)	(228)
Net cash provided by operating activities	144,520	51,750	69,630
Cash flows from investing activities:			
Additions to oil and natural gas properties	(367,245)	(74,668)	(178,637)
Proceeds from sale of oil and natural gas properties	17,918	—	—
Changes in inventory	(20,872)	(7,881)	—
Additions to other property and equipment	(41,516)	(2,054)	(1,472)
Purchases of short term investments	(331,624)	(86,575)	—
Sales of short term investments	187,922	6,277	—
(Increase) decrease in drilling advances paid	(794)	(274)	798
Changes to restricted cash	—	555	(555)
Net cash used by investing activities	(556,211)	(164,620)	(179,866)
Cash flows from financing activities:			
Proceeds from issuance of common stock, net of issuance costs	277,547	261,725	—
Proceeds from exercise of employee stock options	3,884	1,219	2,066
Proceeds from Senior Notes offering	300,000	—	—
Redemption of Senior Notes offering	(168,683)	—	—
Redemption of Series A Preferred Stock	(10,101)	—	—
Repurchases of common stock	(524)	(931)	(348)
Increase in senior credit facility	—	—	139,500
Repayment of senior credit facility	—	(145,000)	(4,500)
Deferred loan fees paid and equity costs	(7,470)	(3,405)	(302)
Net cash provided by financing activities	394,653	113,608	136,416
Net increase (decrease) in cash and cash equivalents	(17,038)	738	26,180
Cash and cash equivalents, beginning of year	40,781	40,043	13,863
Cash and cash equivalents, end of year	$ 23,743	$ 40,781	$ 40,043

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

BRIGHAM EXPLORATION COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Nature of Operations

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

2. Summary of Significant Accounting Policies

Use of Estimates

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

Reclassifications

Certain reclassifications have been made to prior years' reported amounts in order to conform with the current year presentation. These reclassifications did not impact our net income, stockholders' equity or cash flows.

Principles of Consolidation

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

Cash and Cash Equivalents

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

Investments

Investments consist primarily of certificates of deposit, corporate debt, and government securities, all of which are classified as "available-for-sale" and stated at fair value. Accordingly, unrealized gains and losses and any related deferred income tax effects are excluded from earnings and reported as a separate component of stockholders' equity. Realized gains or losses are computed based on specific identification of the securities sold.

Inventory

Inventory, which is included in current assets, includes tubular goods and other lease and well equipment which we plan to utilize in our ongoing exploration and development activities. Inventory also includes barrels of crude oil that was produced in the Williston Basin during operations but not yet sold at year-end in the amount of 46,129 barrels and 16,475 barrels at December 31, 2010 and 2009, respectively. Inventories are carried at the lower of cost or market using the specific identification method. Crude oil was valued at Brigham's estimated production cost of $299,000 and $136,000 at December 31, 2010 and 2009, respectively.

Property and Equipment

Brigham uses the full cost method of accounting for oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain payroll, asset retirement costs, other internal costs, and interest incurred for the purpose of finding oil and natural gas reserves, are capitalized. Internal costs that are capitalized are directly attributable to acquisition, exploration and development activities and do not include costs related to production, general corporate overhead or similar activities. Costs associated with production and general corporate activities are expensed in the period incurred. Proceeds from the sale of oil and natural gas properties are applied to reduce the capitalized costs of oil and natural gas properties unless the sale would significantly alter the relationship between capitalized costs and proved reserves, in which case a gain or loss is recognized.

Capitalized costs associated with impaired properties and capitalized costs related to properties having proved reserves, plus the estimated future development costs, and asset retirement costs under Financial Accounting Standards Board Accounting Standards Codification Topic 410 "Asset Retirement and Environmental Obligations" (FASB ASC 410), are amortized using the unit-of-production method based on proved reserves. Capitalized costs of oil and natural gas properties, net of accumulated amortization and deferred income taxes, are limited to the total of estimated future net cash flows from proved oil and natural gas reserves, discounted at ten percent, plus the cost of unevaluated properties. The estimated future net cash flows at December 31, 2008 were determined using prices at the end of the year. Under certain specific conditions, companies could elect to use subsequent prices for determining the estimated future net cash flows. Brigham elected to use subsequent pricing for this purpose at December 31, 2008. Under new rules issued by the Securities and Exchange Commission, the estimated future net cash flows for at December 31, 2010 and 2009 were determined using a 12-month average price. The average is calculated using the first day of the month price for each of the 12 months that make up the reporting period. The use of subsequent pricing is no longer allowed. See "New Pronouncements" below for additional detail regarding the new rules. There are many factors, including global events that may influence the production, processing, marketing and price of oil and natural gas. A reduction in the valuation of oil and natural gas properties resulting from declining prices or production could adversely impact depletion rates and capitalized cost limitations. Capitalized costs associated with properties that have not been evaluated through drilling or seismic analysis, including exploration wells in progress at December 31, 2010 and 2009, are excluded from the unit-of-production amortization. Exclusions are adjusted annually based on drilling results and interpretative analysis.

Other property and equipment, which primarily consists of water disposal wells and gathering systems, is depreciated on a straight-line basis over the estimated useful lives of the assets after considering salvage value. Estimated useful lives are as follows:

Support infrastructure wells and gathering systems	15 years
Furniture and fixtures	10 years
Machinery and equipment	3 – 10 years
3-D seismic interpretation workstations and software	3 years
Pipeyard equipment and improvements	7 – 15 years
Field general equipment	3 – 15 years
Land	—

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.

Asset Retirement Obligations

Brigham records the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized.

Revenue Recognition

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

Brigham recognizes revenues from the sale of natural gas using the entitlements method of accounting. Under this method, revenues are recognized based on Brigham's entitled ownership percentage of sales of natural gas to purchasers. Gas imbalances occur when Brigham sells more or less than its entitled ownership percentage of total natural gas production. When Brigham receives less than its entitled share, a receivable is recorded. When Brigham receives more than its entitled share, a liability is recorded.

Brigham recognizes revenue from its support infrastructure operations, which provide the usage of its oil, natural gas, waste water and fresh water gathering lines. Brigham also provides water disposal services for certain operated wells currently drilling or that have been placed on production. Any intercompany revenues and expenses have been eliminated for financial statement presentation.

Derivative Instruments and Hedging Activities

Brigham accounts for its derivative activities under Financial Accounting Standards Board Accounting Standards Codification Topic 815 "Derivatives and Hedging" (FASB ASC 815). FASB ASC 815 establishes accounting and reporting standards requiring that every derivative instrument be recorded on the balance sheet as either an asset or a liability measured at its fair value. The statement requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Brigham uses derivative instruments to manage market risks resulting from fluctuations in the prices of crude oil and natural gas. Brigham periodically enters into derivative contracts, including price swaps, ceilings and floors, which require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a fixed quantity of oil or natural gas without the exchange of underlying volumes. The notional amounts of these financial instruments are based on expected production from existing wells.

At the inception of a derivative contract, Brigham historically designated the derivative as a cash flow hedge. Derivatives were recorded on the balance sheet at fair value and changes in the fair value of derivatives were recorded each period in net income or other comprehensive income, depending on whether a derivative was designated as part of a hedge transaction and, if it was, depending on the type of hedge transaction. On October 1, 2006, Brigham de-designated all derivates that were previously classified as cash flow hedges and, in addition, Brigham elected not to designate any additional derivative contracts as accounting hedges under FASB ASC Topic 815. As such, all derivative positions are carried at their fair value on the consolidated balance sheet and are marked-to-market at the end of each period. Any realized and unrealized gains or losses are recorded as gain (loss) on derivatives, net, as an increase or decrease in revenue on the consolidated statement of operations rather than as a component of other comprehensive income or other income (expense).

Other Comprehensive Income (Loss)

Brigham follows the provisions of Financial Accounting Standards Board Accounting Standards Codification Topic 220 "Comprehensive Income" (FASB ASC 220)", which establishes standards for reporting comprehensive income. In addition to net income (loss), comprehensive income (loss) includes all changes in equity during a period, except those resulting from investments and distributions to stockholders of Brigham.

The following table reflects the components of other comprehensive income (loss) for the years ended December 31, 2010, 2009 and 2008 (in thousands):

	2010	2009	2008
Balance, beginning of year	$ (205)	$ —	$ 115
Unrealized (gains) losses on investments	196	(205)	—
Tax benefits (provisions) related to cash flow hedges	—	—	61
Net (gains) losses included in earnings	—	—	(176)
Balance, end of year	$ (9)	$ (205)	$ —

Stock Based Compensation

Brigham applies Financial Accounting Standards Board Accounting Standards Codification Topic 718 "Compensation — Stock Compensation" (FASB ASC 718) to account for stock based compensation. See Note 13, "Stock Based Compensation," for a full discussion of our stock-based compensation.

Income Taxes

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

Deferred Loan Fees

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

Segment Information

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

Treasury Stock

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

Mandatorily Redeemable Preferred Stock

The Series A Preferred Stock is presented in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 480 "Distinguishing Liabilities from Equity" (FASB ASC 480). FASB ASC 480 requires an issuer to classify certain financial instruments within its scope, such as mandatorily redeemable preferred stock, as liabilities (or assets in some circumstances). FASB ASC 480 defines a financial instrument as mandatorily redeemable if it embodies an unconditional obligation requiring the issuer to redeem the instrument by transferring its assets at a specified or determinable date(s) or upon an event certain to occur.

New Pronouncements

On December 31, 2008, the SEC published the final rules and interpretations updating its oil and gas reporting requirements. Many of the revisions are updates to definitions in the existing oil and gas rules to make them consistent with the petroleum resource management system, which is a widely accepted standard for the management of petroleum resources that was developed by several industry organizations. Key revisions include the ability to include nontraditional resources in reserves, the use of new technology for determining reserves, permitting disclosure of probable and possible reserves, and changes to the pricing used to determine reserves in that companies must use a 12-month average price. The average is calculated using the first-day-of-the-month price for each of the 12 months that make up the reporting period. The SEC required companies to comply with the amended disclosure requirements for registration statements filed after January 1, 2010, and for annual reports for fiscal years ending on or after December 15, 2009. Early adoption was not permitted. Financial Accounting Standards Board Accounting Standards Codification Topic 932 "Extractive Activities — Oil and Gas" (FASB ASC 932) provides guidance for oil and natural gas reserve related disclosures in the financial statements. Adoption of the new requirements did not have a material impact on Brigham's financial statements.

3. Property and Equipment

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

	December 31,	
	2010	2009
Oil and natural gas properties	$ 1,093,047	$ 696,229
Accumulated depletion	(423,691)	(365,496)
	669,356	330,733

	December 31,	
	2010	2009
Other property and equipment:		
Support infrastructure wells and gathering systems	32,543	—
3-D seismic interpretation workstations and software	1,627	1,619
Office furniture and equipment	3,646	3,307
Pipeyard equipment and improvements	3,686	832
Field general equipment	6,655	1,739
Land	1,264	409
Accumulated depreciation	(6,584)	(4,881)
	42,837	3,025
	$ 712,193	$ 333,758

Depletion expense is based on units-of-production. Production volumes used to determine depletion expense were 2,976 MBoe, 1,796 MBoe, and 1,910 MBoe for 2010, 2009, and 2008 respectively. The depletion rate used to calculate depletion expense was $19.56, $17.88, and $28.02 for 2010, 2009, and 2008, respectively.

Brigham capitalizes certain payroll and other internal costs directly attributable to acquisition, exploration and development activities as part of its investment in oil and natural gas properties over the periods benefited by these activities. Capitalized costs do not include any costs related to production, general corporate overhead, or similar activities. Capitalized costs are summarized as follows for the years ended December 31, 2010, 2009 and 2008 (in thousands):

	Year Ended December 31,		
	2010	2009	2008
Capitalized certain payroll and other internal costs	$ 12,552	$ 7,718	$ 7,994
Capitalized interest costs	9,770	4,713	4,761
	$ 22,322	$ 12,431	$ 12,755

The risk that Brigham will experience a ceiling test writedown increases when oil and gas prices are depressed or if Brigham has substantial downward revisions in its estimated proved reserves. Based on oil and gas prices in effect at the end of December 2008 ($5.710 per MMBtu for Henry Hub natural gas and $44.60 per barrel for West Texas Intermediate oil, adjusted for differentials), the unamortized cost of Brigham's oil and gas properties exceeded the ceiling limit by $148.6 million, net of tax. As a result, Brigham was required to record a writedown of the net capitalized costs of its oil and gas properties in the amount of $237.2 million at December 31, 2008.

Based on oil and gas prices in effect at the end of March 2009 ($3.63 per MMBtu for Henry Hub gas and $49.65 per barrel for West Texas Intermediate oil, adjusted for differentials), the unamortized cost of Brigham's oil and gas properties exceeded the ceiling limit by $71.9 million, net of tax. As a result, Brigham was required to record a writedown of the net capitalized costs of its oil and gas properties in the amount of $114.8 million at March 31, 2009. Based on the 12-month average oil and gas prices for the year ended December 31, 2009 ($3.87 per MMBtu for Henry Hub natural gas and $61.18 per barrel for West Texas Intermediate oil, adjusted for differentials), the unamortized cost of Brigham's oil and gas properties did not exceed the ceiling limit. Therefore, Brigham was not required to writedown the net capitalized costs of its oil and gas properties at December 31, 2009.

Based on the 12-month average oil and gas prices for the year ended December 31, 2010 ($4.38 per MMBtu for Henry Hub natural gas and $79.43 per barrel for West Texas Intermediate oil, adjusted for differentials), the unamortized cost of Brigham's oil and gas properties did not exceed the ceiling limit. Therefore, Brigham was not required to writedown the net capitalized costs of its oil and gas properties at December 31, 2010.

During the second quarter 2010, Brigham sold a portion of its proved developed producing West Texas assets for $14 million with an effective date of January 1, 2010. The proceeds for the sale were applied to reduce the capitalized costs of oil and gas properties

4. Common Stock

In May 2009, Brigham completed a public offering of common stock pursuant to a shelf registration statement. Brigham sold 36,292,117 shares of its common stock at a price of $2.75 per share and received net proceeds of $93.4 million after underwriting fees and offering expenses.

In October 2009, Brigham completed a public offering of common stock pursuant to a shelf registration statement. Brigham sold 16,000,000 shares of its common stock at a price of $10.50 per share and received net proceeds of $159.9 million after underwriting fees and offering expenses. In November 2009, the underwriters elected to exercise a portion of the over-allotment option associated with this equity offering. Brigham issued 837,523 additional shares of common stock and received net proceeds of $8.4 million after underwriting fees and offering expenses.

In April 2010, Brigham completed a public offering of common stock pursuant to a shelf registration statement. Brigham sold 16,100,000 shares of its common stock at a price of $18.00 per share and received net proceeds of approximately $277.5 million after deducting underwriting fees and offering expenses.

5. Senior Credit Facility and Senior Notes

The following table reflects the outstanding balances of the senior credit facility and senior notes for the years ended December 31, 2010 and 2009:

	December 31,	
	2010	2009
	(In thousands)	
Senior Credit Facility	$ —	$ —
Senior Notes	300,000	160,000
Discount on Senior Notes	—	(1,032)
Total Debt	$ 300,000	$ 158,968
Less: Current Maturities	—	—
Total Long-Term Debt	$ 300,000	$ 158,968

Senior Credit Facility

In May 2009, in conjunction with Brigham's regularly scheduled semi-annual redetermination and Brigham's common stock offering, the borrowing base was reset to $110 million. On July 24, 2009, Brigham amended and restated the Senior Credit Facility to extend the maturity of the agreement from June 2010 to July 2012. During October 2009, Brigham used a portion of the proceeds from the October stock offering to repay borrowings under the Senior Credit Facility of $110 million. Brigham had no borrowings outstanding under its Senior Credit Facility at December 31, 2010 and 2009.

Borrowings under the Senior Credit Facility bear interest, at Brigham's election, at a base rate (as the term was defined in the Senior Credit Facility) or Eurodollar rate, plus in each case an applicable margin that was reset quarterly (2.5% at December 31, 2010). The applicable interest rate margin varied from 1.5% to 2.5% in the case of borrowings based on the base rate (as the term was defined in the Senior Credit Facility) and from 2.5% to 3.5% in the case of borrowings based on the Eurodollar rate, depending on percentage of the available borrowing base utilized. In addition, Brigham was required to pay a commitment fee on the unused portion of its borrowing base (0.50% at December 31, 2010). Borrowings under the Senior Credit Facility were collateralized by substantially all of Brigham's oil and natural gas properties under first liens.

The Senior Credit Facility contained various covenants, including among other restrictions on liens, restrictions on incurring other indebtedness, restrictions on mergers, restrictions on investments, and restrictions on hedging activity of a speculative nature or with counterparties having credit ratings below specified levels. The Senior Credit Facility required Brigham to maintain a current ratio (as defined) of at least 1 to 1. The Senior Credit Facility also required Brigham to maintain an interest coverage ratio for the four most recent quarters as of December 31, 2010 of at least 2.5 to 1. The Senior Credit Facility also required Brigham to maintain a net leverage ratio for the quarters ending December 31, 2010 and March 31, 2011 not greater than 4.25 to 1, and thereafter not greater than 4.0 to 1. At December 31, 2010, Brigham was in compliance with all covenants under the Senior Credit Facility.

Subsequent to December 31, 2010, Brigham amended and restated its Senior Credit Facility to provide for revolving credit borrowings up to $600 million, with an initial borrowing base of $325 million. Borrowings under the new Senior Credit Facility cannot exceed its borrowing base, which is determined at least semi-annually. Brigham also extended the maturity of its Senior Credit Facility from July 2012 to February 2016. As part of the new Senior Credit Facility, the requirement to maintain a minimum interest coverage ratio was removed. See Note 16 "Subsequent Events."

Senior Notes

On September 27, 2010, Brigham issued $300 million of 8 3/4% Senior Notes due October 2018 (collectively the " 8 3/4% Senior Notes"). The notes were priced at 100% of their face value and are fully and unconditionally guaranteed by Brigham and its wholly-owned subsidiaries, Brigham, Inc. and Brigham Oil & Gas, L.P. Brigham does not have any independent assets or operations.

In connection with the issuance of the 8 3/4% Senior Notes, Brigham tendered for and purchased $154.4 million of its 9 5/8% Senior Notes due 2014 and previously issued in 2006 and 2007 on September 27, 2010. Brigham recorded a $10.9 million loss upon the purchase of the 9 5/8% Senior Notes. Brigham redeemed the remaining $5.6 million of the 9 5/8% Senior Notes on October 8, 2010. Brigham recorded a $360,000 loss upon the redemption of the remaining 9 5/8% Senior Notes.

The indenture governing the 8 3/4% Senior Notes contains customary events of default. Upon the occurrence of certain events of default, the trustee or the holders of the 8 3/4% Senior Notes may declare all outstanding 8 3/4% Senior Notes to be due and payable immediately. The indenture also contains customary restrictions and covenants which could potentially limit Brigham's flexibility to manage and fund its business. At December 31, 2010, Brigham was in compliance with all covenants under the indenture.

6. Preferred Stock

Series A Mandatorily Redeemable Preferred Stock

The following table reflects the outstanding shares of Series A mandatorily redeemable preferred stock and the activity related thereto for the years ended December 31, 2010 and 2009 (in thousands, except share amounts):

	Year Ended December 31, 2010		Year Ended December 31, 2009	
	Shares	Amounts	Shares	Amounts
Balance, beginning of year	505,051	$ 10,101	505,051	$ 10,101
Balance, end of year	—	$ —	505,051	$ 10,101

Brigham had designated 2,250,000 shares of preferred stock as Series A Preferred Stock. The Series A Preferred Stock had a par value of $0.01 per share and a stated value of $20 per share. The Series A Preferred Stock was cumulative and paid dividends quarterly at a rate of 6% per annum of the stated value in cash. The Series A Preferred Stock was set to mature on October 31, 2010 and was redeemable at Brigham's option at 100% or 101% of stated value (depending upon certain conditions) at anytime prior to maturity. The Series A Preferred Stock did not generally have any voting rights, except for certain approval rights and as required by law.

In June 2010, Brigham exercised its option to redeem all of its Series A mandatorily redeemable preferred stock at 101% of the stated value per share, which was held by DLJ Merchant Banking Partners III, L.P. and affiliated funds, which are managed by affiliates of Credit Suisse Securities (USA), LLC.

7. Asset Retirement Obligations

Brigham has asset retirement obligations associated with the future plugging and abandonment of proved properties and related facilities. Prior to the adoption of Financial Accounting Standards Board Accounting Standards Codification Topic 410 "Asset Retirement and Environmental Obligations" (FASB ASC 410), Brigham assumed salvage value approximated plugging and abandonment costs. As such, estimated salvage value was not excluded from depletion and plugging and abandonment costs were not accrued for over the life of the oil and gas properties. Under the provisions of FASB ASC 410, the fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. Brigham has no assets that are legally restricted for purposes of settling asset retirement obligations.

The following table summarizes Brigham's asset retirement obligation transactions recorded in accordance with the provisions of FASB ASC 410 during the years ended December 31, 2010 and 2009 (in thousands):

	Year Ended December 31,	
	2010	2009
Beginning asset retirement obligations	$ 6,323	$ 5,592
Liabilities incurred for new wells placed on production	814	327
Liabilities settled	(428)	(17)
Revisions to estimates due to sale of oil and gas properties	(1,208)	—
Accretion of discount on asset retirement obligations	422	421
	$ 5,923	$ 6,323

8. Income Taxes

Brigham utilizes the asset and liability approach to measure deferred tax assets and liabilities based on temporary differences existing at each balance sheet date using currently enacted tax rates in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 740 "Income Taxes" (FASB ASC 740). Deferred tax assets and liabilities are adjusted for the effects of changes in tax laws and rates on the date of enactment. Under FASB ASC 740, deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. During 2009, Brigham's deferred tax asset relating to oil and gas properties was increased primarily due to Brigham's ceiling test writedown in the first quarter of 2009. During 2010, Brigham's deferred tax asset decreased for federal and state purposes. After testing to determine if the deferred tax assets would meet the more likely than not criteria, Brigham decreased its federal valuation allowance to $62.3 million and its state valuation allowance to $5.2 million.

The total provision for income taxes consists of the following (dollar amounts are in thousands):

	Year Ended December 31,		
	2010	2009	2008
Current income taxes	$ —	$ —	$ —
Deferred income taxes (benefits):			
Federal	14,805	(43,029)	(71,445)
State	1,655	(1,141)	(5,745)
Federal and state valuation allowances	(15,376)	43,937	34,489
	$ 1,084	$ (233)	$ (42,701)

The provision for income taxes differs from the amount computed by applying the statutory federal income tax rate to net income before taxes. The sources of the tax effects of the differences are as follows (dollar amounts are in thousands):

	Year Ended December 31,		
	2010	2009	2008
Tax (benefit) at statutory rate	$ 15,393	$ (43,129)	$ (71,732)
Add the effect of:			
Nondeductible expenses, net of tax exempt income	7	1	6
Preferred stock dividends	129	212	212
Incentive stock options not exercised	93	26	47
State income taxes (benefits), net of federal deduction	1,076	(741)	(3,734)
State valuation allowance, net of federal deduction	(369)	644	2,455
Federal valuation allowance	(15,303)	42,719	30,002
Other	58	35	43
	$ 1,084	$ (233)	$ (42,701)

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

	December 31,	
	2010	2009
Deferred tax assets		
Current:		
Unrealized hedging and other derivative losses	$ 3,504	$ 913
State deferred taxes	381	—
Other	82	36
Current	3,967	949
Non-current:		
Net operating loss carryforwards (NOLs)	82,394	84,706
Percentage depletion carryforwards	4,896	4,433
Stock compensation	4,115	3,328
Asset retirement obligations	2,073	2,213
Unrealized derivative losses	3,100	318
Other	784	81
Non-current	97,362	95,079
	101,329	96,028
Valuation allowance	(62,309)	(77,153)
Total net deferred tax assets	39,020	18,875
Deferred tax liabilities		
Current:		
Unrealized derivative gains	$ (1,630)	$ (403)
Current	(1,630)	(403)
Non-current:		
Depreciable and depletable property	(36,851)	(18,392)
Other	(539)	(80)
Non-current	(37,390)	(18,472)
Total net deferred tax liabilities	(39,020)	(18,875)
Total federal deferred tax asset (liability)	—	—
Total state deferred tax asset (liability)	(1,088)	—
Total deferred tax asset (liability)	$ (1,088)	$ —

At December 31, 2010, Brigham has regular U. S. Federal tax NOLs of approximately $249 million available as a deduction against future taxable income. Additionally, Brigham has approximately $234 million of U. S. Federal alternative minimum tax ("AMT") NOLs. The NOLs expire from 2012 through 2029. The value of these NOLs depends on the ability of Brigham to generate taxable income. Brigham also has U. S. State tax NOLs of approximately $93.7 million (of which $19.5 million relates to the Williston Basin) and a Texas Franchise tax credit carryover of approximately $1.4 million. The decreases in the valuation allowances have no impact on Brigham's NOL positions for federal and state tax purposes.

Brigham believes an Internal Revenue Code Sec. 382 ownership change may have occurred in March 2001 and in November 2005, as a result of a potential 50% change in ownership among its 5% shareholders over a three-year period. Limitations on the utilization of Brigham's NOLs may result from the March 2001 and November 2005 ownership changes. The limitations approximate $5.2 million annually and $22 million annually, respectively.

On January 1, 2007, Brigham adopted additional provisions under FASB ASC 740, which provides that the tax effects from an uncertain tax position can be recognized in the financial statements only if the position is more likely than not of being sustained if the position were to be challenged by a taxing authority. In 2006 and 2007, Brigham examined the tax positions taken in its tax returns and determined that the full values of the uncertain tax positions were reflected as part of its deferred tax liabilities and reclassified these liabilities to other tax liabilities on the consolidated balance sheet. In 2008, Brigham received approval from the Internal Revenue Service to change its method of accounting for certain geological and geophysical costs and no longer has a liability for uncertain tax positions. As a result, as of December 31, 2008, Brigham eliminated the other tax liabilities in its consolidated balance sheet.

The tax years that remain subject to examination by Federal and major state tax jurisdictions are the years ended December 31, 2010, 2009, 2008, and 2007. In addition, Brigham is open to examination for the years 1997 through 2006, resulting from NOLs generated and available for carryforward.

9. Net Income Available Per Common Share

Basic earnings per share are computed by dividing net income (loss) available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted EPS is computed by dividing net income by the weighted average number of common shares and potential common shares outstanding (if dilutive) during each period. Potential common shares include stock options and restricted stock. The number of potential common shares outstanding relating to stock options and restricted stock is computed using the treasury stock method.

	Year Ended December 31,		
	2010	2009	2008
	(In thousands, except per share amounts)		
Basic EPS:			
Income (loss) available to common stockholders	$ 42,896	$ (122,992)	$ (162,247)
Weighted average common shares outstanding — basic	111,355	70,569	45,441
Basic EPS:			
Income (loss) available to common stockholders	$ 0.39	$ (1.74)	$ (3.57)
Diluted EPS:			
Income (loss) available to common stockholders — diluted	$ 42,896	$ (122,992)	$ (162,247)
Common shares outstanding	111,355	70,569	45,441
Effect of dilutive securities:			
Stock options and restricted stock	1,953	—	—
Potentially dilutive common shares	1,953	—	—
Adjusted common shares outstanding — diluted	113,308	70,569	45,441
Diluted EPS:			
Income (loss) available to common stockholders	$ 0.38	$ (1.74)	$ (3.57)

At December 31, 2010, 2009, and 2008, potential dilution of approximately 1.0 million, 4.7 million, and 3.7 million shares of common stock, respectively, related to mandatorily redeemable preferred stock and options were outstanding, but were not included in the computation of diluted income (loss) per share because the effect of these instruments would have been anti-dilutive.

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

Litigation

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

As of December 31, 2010, there are no known environmental or other regulatory matters related to Brigham's operations that are reasonably expected to result in a material liability to Brigham. Compliance with environmental laws and regulations has not had, and is not expected to have, a material adverse effect on Brigham's financial position, results of operations or cash flows.

Operating Lease Commitments

Brigham leases office equipment and space under operating leases expiring at various dates. The noncancelable term of the leases for Brigham's office space expires in 2012. Brigham is subject to early termination fees for four drilling rigs under a contract that is quarter-to-quarter through May 2011. Brigham is also subject to early termination fees for each day remaining under the primary term for five drilling rigs with renewable terms of a maximum of six months. Additionally, Brigham is subject to early termination fees for each day remaining under the primary term for one drilling rig with a renewable quarterly term. Finally, Brigham is subject to early termination fees for each day remaining under the contract for two walking rigs. Both of these contracts contain three year terms and begin once Brigham receives the rigs. The future minimum annual rental payments under the noncancelable terms of these leases and potential fees for early termination of the drilling rig contracts at December 31, 2010 are as follows (in thousands):

2011	10,225
2012	11,191
2013	10,950
2014	10,950
2015	465
Thereafter	
	$ 43,781

Rental expense for the years ended December 31, 2010, 2009 and 2008 was approximately $789,000, $804,000, and $770,000, respectively.

Major Purchasers

The following purchasers accounted for 10% or more of Brigham's oil and natural gas sales for the years ended December 31, 2010, 2009 and 2008:

	2010	2009	2008
Purchaser A	—	—	21%
Purchaser B	—	31%	19%
Purchaser C	17%	13%	—
Purchaser D	19%	—	—
Purchaser E	18%	—	—
Purchaser F	13%	—	—

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

Factors Which May Affect Future Operations

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

11. Derivative Instruments and Hedging Activities

Brigham utilizes various commodity swap and option contracts to (i) reduce the effects of volatility in price changes on the oil and natural gas commodities it produces and sells, (ii) reduce commodity price risk and (iii) provide a base level of cash flow in order to assure it can execute at least a portion of its capital spending plans.

Natural Gas and Crude Oil Derivative Contracts

Cash flow hedges

Brigham enters into contracts to hedge against the variability in cash flows associated with the forecasted sale of future oil and gas production. Brigham's hedges consist of costless collars (purchased put options and written call options), three-way collars (a standard collar plus a sold put below the floor price of the collar), purchased put options, written call options, and swaps. The costless collars and three-way collars are used to establish floor and ceiling prices on anticipated future oil and natural gas production. There are no net premiums paid or received when Brigham enters into these option agreements. Brigham has elected not to designate any of its derivative contracts as cash flow hedges for accounting purposes under Financial Accounting Standards Board Accounting Standards Codification Topic 815 "Derivatives and Hedging" (FASB ASC 815). As such, all derivative positions are carried at their fair value on the consolidated balance sheet and are marked-to-market at the end of each period. See Note 12, "Fair Values", for a discussion of the calculation of the fair values of oil and natural gas derivative contracts. Any realized and unrealized gains or losses are recorded as gain (loss) on derivatives, net, as an increase or decrease in revenue on the consolidated statement of operations.

The following tables reflect Brigham's open commodity derivative contracts at December 31, 2010, the associated volumes and the corresponding weighted average NYMEX reference price.

Settlement Period	Natural Gas (MMBTU)	Oil (Barrels)	Purchased Put Nymex	Written Call Nymex
Natural Gas Costless Collars				
01/01/11 – 03/31/11	120,000		$ 6.50	$ 8.25
01/01/11 – 03/31/11	210,000		$ 6.40	$ 7.80
01/01/11 – 12/31/11	360,000		$ 5.75	$ 7.65
01/01/11 – 12/31/11	480,000		$ 5.75	$ 7.40
04/01/11 – 12/31/11	360,000		$ 5.00	$ 6.55
Oil Costless Collars				
01/01/11 – 07/31/12		289,000	$ 65.00	$ 97.20
01/01/11 – 07/31/12		289,000	$ 65.00	$ 98.55
01/01/11 – 07/31/12		289,000	$ 65.00	$ 100.40
01/01/11 – 07/31/12		289,000	$ 65.00	$ 100.00
01/01/11 – 02/28/11		29,500	$ 65.00	$ 98.75
01/01/11 – 02/28/11		10,000	$ 70.00	$ 92.00
01/01/11 – 02/28/11		8,000	$ 75.00	$ 103.50
01/01/11 – 03/31/11		9,000	$ 75.00	$ 93.50
01/01/11 – 06/30/11		18,000	$ 65.00	$ 97.50
01/01/11 – 06/30/11		24,000	$ 70.00	$ 92.50
01/01/11 – 07/31/11		21,000	$ 70.00	$ 94.80
01/01/11 – 12/31/11		84,000	$ 65.00	$ 88.25
01/01/11 – 12/31/11		60,000	$ 60.00	$ 97.25
01/01/11 – 12/31/11		60,000	$ 65.00	$ 108.00
01/01/11 – 12/31/11		48,000	$ 70.00	$ 106.80
01/01/11 – 12/31/11		48,000	$ 75.00	$ 102.60
01/01/11 – 12/31/11		36,000	$ 65.00	$ 100.00
01/01/11 – 12/31/11		36,000	$ 75.00	$ 104.30
01/01/11 – 12/31/11		182,500	$ 65.00	$ 100.00
03/01/11 – 04/30/11		16,000	$ 75.00	$ 104.50
03/01/11 – 08/31/11		46,000	$ 65.00	$ 96.75
03/01/11 – 08/31/11		46,000	$ 65.00	$ 94.80
05/01/11 – 12/31/11		122,500	$ 65.00	$ 100.00
05/01/11 – 12/31/11		122,500	$ 65.00	$ 106.50
07/01/11 – 09/30/11		9,000	$ 70.00	$ 95.00
07/01/11 – 12/31/11		12,000	$ 75.00	$ 103.00
07/01/11 – 12/31/11		12,000	$ 75.00	$ 95.15

Settlement Period	Natural Gas (MMBTU)	Oil (Barrels)	Purchased Put Nymex	Written Call Nymex
09/01/11 – 12/31/11		61,000	$ 65.00	$ 99.00
09/01/11 – 12/31/11		61,000	$ 65.00	$ 97.40
10/01/11 – 12/31/11		6,000	$ 70.00	$ 96.35
01/01/12 – 06/30/12		60,000	$ 75.00	$ 106.90
01/01/12 – 06/30/12		182,000	$ 65.00	$ 100.75
01/01/12 – 06/30/12		91,000	$ 65.00	$ 101.00
01/01/12 – 06/30/12		182,000	$ 65.00	$ 99.25
01/01/12 – 06/30/12		91,000	$ 65.00	$ 102.75
01/01/12 – 06/30/12		136,500	$ 65.00	$ 107.25
01/01/12 – 07/31/12		106,500	$ 65.00	$ 110.00
07/01/12 – 07/31/12		62,000	$ 65.00	$ 102.25
07/01/12 – 07/31/12		31,000	$ 65.00	$ 105.25
07/01/12 – 09/30/12		92,000	$ 65.00	$ 109.40
08/01/12 – 09/30/12		61,000	$ 65.00	$ 110.25
08/01/12 – 09/30/12		61,000	$ 65.00	$ 112.00
08/01/12 – 10/31/12		92,000	$ 70.00	$ 110.90
08/01/12 – 10/31/12		92,000	$ 70.00	$ 106.50
10/01/12 – 10/31/12		62,000	$ 65.00	$ 112.65
10/01/12 – 10/31/12		31,000	$ 70.00	$ 110.90
11/01/12 – 12/31/12		122,000	$ 70.00	$ 107.70
11/01/12 – 12/31/12		122,000	$ 70.00	$ 110.00
Crude Oil Calls				
01/01/11 – 06/30/11		90,500		$ 95.00
01/01/11 – 06/30/11		90,500		$ 97.50
Crude Oil Puts				
01/01/11 – 06/30/12		273,500	$ 65.00	
01/01/11 – 06/30/12		273,500	$ 65.00	
07/01/11 – 06/30/12		91,500	$ 65.00	
07/01/11 – 06/30/12		91,500	$ 65.00	

The following tables reflect commodity derivative contracts entered subsequent to December 31, 2010, the associated volumes and the corresponding weighted average NYMEX reference price.

Settlement Period	Natural Gas (MMBTU)	Oil (Barrels)	Purchased Put Nymex	Written Call Nymex
Oil Costless Collars				
07/01/12 – 07/31/12		62,000	$ 75.00	$ 114.00
08/01/12 – 10/31/12		276,000	$ 75.00	$ 112.50
11/01/12 – 12/30/12		244,000	$ 75.00	$ 112.50
01/01/13 – 02/28/13		118,000	$ 75.00	$ 113.05
01/01/13 – 03/31/13		180,000	$ 80.00	$ 120.00
03/01/13 – 03/31/13		62,000	$ 80.00	$ 120.00
Crude Oil Calls				
07/01/11 – 12/31/11		276,000		$ 100.00
Crude Oil Puts				
07/01/12 – 12/31/12		276,000	$ 80.00	

Additional Disclosures about Derivative Instruments and Hedging Activities

At December 31, 2010 and 2009, Brigham had derivative financial instruments under FASB ASC 815 recorded on the consolidated balance sheet as set forth below:

Type of Contract	Balance Sheet Location	Dec 31, 2010 Estimated Fair Value (in thousands)	Dec 31, 2009 Estimated Fair Value (in thousands)
Derivatives Not Designated as Hedging Instruments			
Derivative Assets:			
Natural gas and oil contracts	Other current assets	$ 2,557	$ 1,152
Natural gas and oil contracts	Other non-current assets	309	186
Total Derivative Assets		$ 2,866	$ 1,338
Derivative Liabilities:			
Natural gas and oil contracts	Derivative liabilities — current	$ (9,442)	$ (2,405)
Natural gas and oil contracts	Other non-current liabilities	(8,575)	(909)
Total Derivative Liabilities		$ (18,017)	$ (3,314)

For the three years ended December 31, 2010 and 2009, the effect on income in the consolidated statement of operations for derivative financial instruments under FASB ASC 815 was as follows:

Type of Contract	Statement of Operations Location of Gain (Loss)	Year Ended Dec 31, 2010 Amount of Gain (Loss) (in thousands)	Year Ended Dec 31, 2009 Amount of Gain (Loss) (in thousands)
Derivatives Not Designated as Hedging Instruments			
Natural gas contracts	Gain (loss) on derivatives, net	$ 4,210	$ 7,061
Oil contracts	Gain (loss) on derivatives, net	(14,276)	(4,997)
Total Derivative Gain (loss)		$ (10,066)	$ 2,064

The use of derivative transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. Brigham's derivative contracts are with multiple counterparties to minimize its exposure to any individual counterparty and Brigham has netting arrangements with all of its counterparties that provide for offsetting payables against receivables from separate derivative instruments with that counterparty.

12. Fair Values

Brigham adopted Financial Accounting Standards Board Accounting Standards Codification Topic 820 "Fair Value Measurements and Disclosures" (FASB ASC 820) on January 1, 2008, as it relates to financial assets and liabilities. Brigham adopted FASB ASC 820 on January 1, 2009, as it relates to nonfinancial assets and liabilities. FASB ASC 820 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The three levels of the fair value hierarchy defined by FASB ASC 820 are as follows:

- Level 1 — Unadjusted quoted prices are available in active markets for identical assets or liabilities.
- Level 2 — Pricing inputs, other than quoted prices within Level 1, that are either directly or indirectly observable.
- Level 3 — Pricing inputs that are unobservable requiring the use of valuation methodologies that result in management's best estimate of fair value.

As such, the fair values of Brigham's derivative financial instruments reflect Brigham's estimate of the default risk of the parties in accordance with FASB ASC 820. Brigham determines the fair value of derivative financial instruments based on counterparties' valuation models that utilize market-corroborated inputs. The fair value of all derivative contracts is reflected on the balance sheet as detailed in the following schedule. The current asset and liability amounts represent the fair values expected to be included in the results of operations for the subsequent year.

		Fair Value Measurements at December 31, 2010 Using		
Description	December 31, 2010	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Current derivative liabilities	$ (9,442)	$ —	$ (9,442)	$ —
Other non-current liabilities	(8,575)	—	(8,575)	—
Other current assets	2,557	—	2,557	—
Other non-current assets	309	—	309	—
	$ (15,151)	$ —	$ (15,151)	$ —

		Fair Value Measurements at December 31, 2009 Using		
Description	December 31, 2009	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Current derivative liabilities	$ (2,405)	$ —	$ (2,405)	$ —
Other non-current liabilities	(909)	—	(909)	—
Current derivative assets	1,152	—	1,152	—
Other non-current assets	186	—	186	—
	$ (1,976)	$ —	$ (1,976)	$ —

Brigham's assessment of the significance of a particular input to the fair value measurement requires judgment and may effect the valuation of the nonfinancial assets and liabilities and their placement in the fair value hierarchy levels. The fair value of Brigham's asset retirement obligations are determined using discounted cash flow methodologies based on inputs that are not readily available in public markets. The fair value of the asset retirement obligations is reflected on the balance sheet as detailed below.

		Fair Value Measurements at December 31, 2010 Using		
Description	**December 31, 2010**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Other non-current liabilities.....	(5,923)	—	—	(5,923)
	$ (5,923)	$ —	$ —	$ (5,923)

		Fair Value Measurements at December 31, 2009 Using		
Description	**December 31, 2009**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Other non-current liabilities....	(6,323)	—	—	(6,323)
	$ (6,323)	$ —	$ —	$ (6,323)

See Note 7 for a rollforward of the asset retirement obligation.

As of December 31, 2010 and 2009, Brigham held $224.0 and $80.1 million, respectively, of investments in certificates of deposit, corporate debt, and government securities. The fair value of the investments is reflected on the balance sheet as detailed below.

		Fair Value Measurements at December 31, 2010 Using		
Description	**December 31, 2010**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Investments............................	223,991	223,991	—	—
	$ 223,991	$ 223,991	$ —	$ —

		Fair Value Measurements at December 31, 2009 Using		
Description	**December 31, 2009**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Investments............................	80,093	80,093	—	—
	$ 80,093	$ 80,093	$ —	$ —

The following table summarizes, by major security type, the fair value and any unrealized gain (loss) of Brigham's investments. The unrealized gain (loss) is recorded on the consolidated balance sheet as other comprehensive income (loss), a component of stockholders' equity.

Description of Securities	Less Than 12 Months Fair Value	Less Than 12 Months Unrealized Gains (Losses)	12 Months or Greater Fair Value	12 Months or Greater Unrealized Gains (Losses)	Total Fair Value	Total Unrealized Gains (Losses)
Certificates of deposit	$ 241	$ 1	$ —	$ —	$ 241	$ 1
Corporate debt	183,391	68	26,324	(86)	209,715	(18)
Government securities	14,035	8	—	—	14,035	8
Total	$ 197,667	$ 77	$ 26,324	$ (86)	$ 223,991	$ (9)

The cost basis of Brigham's investments in certificates of deposit, corporate bonds and notes, and government securities (in thousands) is $240, $212,464, and $14,103, respectively

Brigham's other financial instruments include cash and cash equivalents, accounts receivable, accounts payable and long-term debt. The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximate fair value because of their immediate or short-term maturities. The carrying value of Brigham's senior credit facility approximates its fair market value since it bears interest at floating market interest rates. The following are estimated fair values and carrying values of our other financial instruments at each of these dates:

	December 31, 2010 (in millions)		December 31, 2009 (in millions)	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Senior Notes	$ 300,000	$ 325,500	$ 160,000	$ 160,000
Series A Preferred Stock	$ —	$ —	$ 10,101	$ 10,166

The fair value of Brigham's Senior Notes is based upon current market quotes and is the estimated amount required to purchase the Senior Notes on the open market.

13. Stock Based Compensation

Brigham applies Financial Accounting Standards Board Accounting Standards Codification Topic 718 "Compensation — Stock Compensation" (FASB ASC 718) to account for stock based compensation. The cost for all stock based awards is based on the grant date fair value estimated in accordance with the provisions of FASB ASC 718 and is amortized on a straight-line basis over the requisite service period including estimates of pre-vesting forfeiture rates. If actual forfeitures differ from the estimates, additional adjustments to compensation expense may be required in future periods. The maximum contractual life of stock based awards is ten years.

The estimated fair value of the options granted during the twelve months ended December 31, 2010, 2009, and 2008 was calculated using a Black-Scholes-Merton option pricing model (Black-Scholes). The following table summarizes the weighted average assumptions used in the Black-Scholes model for each of the three years ended December 31, 2010:

	2010	2009	2008
Risk-free interest rate	2.46%	2.64%	2.78%
Expected life (in years)	5.0	5.0	5.0
Expected volatility	81%	78%	56%
Expected dividend yield	—	—	—
Weighted average fair value per share of stock compensation	$ 12.38	$ 3.41	$ 2.52

The Black-Scholes model incorporates assumptions to value stock based awards. The risk-free rate of interest for periods within the contractual life of the option is based on a zero-coupon U.S. government instrument over the contractual term of the equity instrument. Expected volatility is based on the historical volatility of Brigham's stock for an equal period of the expected term.

Prior to the adoption of FASB ASC 718, Brigham presented all tax benefits of deductions resulting from the exercise of stock options as operating cash flows in the Consolidated Statement of Cash Flows. FASB ASC 718 requires the cash flow resulting from the tax deductions in excess of the compensation cost recognized for those options (excess tax benefits) to be classified as financing cash flows. Brigham did not record any excess tax benefits during the twelve months ended December 31, 2010 and 2009.

The following table summarizes the components of stock based compensation included in general and administrative expense (in thousands (in thousands):

	Twelve Months Ended December 31,		
	2010	2009	2008
Pre-tax stock based compensation expense	$ 4,992	$ 4,282	$ 2,926
Capitalized stock based compensation	(2,316)	(2,003)	(1,334)
Tax benefit	(937)	(798)	(557)
Stock based compensation expense, net	$ 1,739	$ 1,481	$ 1,035

Brigham provides an incentive plan for the issuance of stock options, stock appreciation rights, stock, restricted stock, cash or any combination of the foregoing. The objective of this plan is to provide incentive and reward key employees whose performance may have a significant impact on the success of Brigham. It is Brigham's policy to use unissued shares of stock when stock options are exercised. The number of shares available under the plan is equal to the lesser of 9,966,003 or 12% of the total number of shares of common stock outstanding. At December 31, 2010, approximately 1,746,015 shares remain available for grant under the current incentive plan. The Compensation Committee of the Board of Directors determines the type of awards made to each participant and the terms, conditions and limitations applicable to each award. Except for one series of stock option grants, options granted subsequent to March 4, 1997 have an exercise price equal to the fair market value of Brigham's common stock on the date of grant, vest over five years and have a maximum contractual life of ten years.

Brigham also maintains a director stock option plan under which stock options are awarded to non-employee directors. Options granted under this plan have an exercise price equal to the fair market value of Brigham common stock on the date of grant and vest over five years. Stockholders have authorized the issuance of 1,000,000 shares to non-employee directors and approximately 516,800 remain available for grant under the director stock option plan.

The following table summarizes option activity under the incentive plans for each of the three years ended December 31, 2010:

	2010		2009		2008	
	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
Options outstanding at beginning of year	4,170,137	$ 5.14	3,128,651	$ 7.00	3,046,166	$ 7.14
Granted	1,029,500	$ 19.27	2,846,975	$ 4.80	534,000	$ 5.08
Forfeited or cancelled	(22,200)	$ 4.32	(1,549,675)	$ 8.30	(65,300)	$ 7.79
Exercised	(741,037)	$ 5.20	(255,814)	$ 4.89	(386,215)	$ 5.35
Options outstanding at end of year	4,436,400	$ 8.41	4,170,137	$ 5.14	3,128,651	$ 7.00
Options exercisable at end of year	675,620	$ 5.83	691,962	$ 6.17	1,954,851	$ 7.17

The weighted-average grant-date fair value of share options granted during the years ended December 31, 2010, 2009, and 2008 was $12.38, $3.41, and $2.52, respectively. The total intrinsic value of options exercised during the years ended December 31, 2010, 2009 and 2008 was $10.2 million, $1.5 million, and $2.4 million, respectively.

The following table summarizes information about stock options outstanding at December 31, 2010:

	Options Outstanding			Options Exercisable		
Exercise Price	Number Outstanding at December 31, 2010	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable at December 31, 2010	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price
$2.20 to $3.11	1,089,000	8.2 years	$ 2.24	137,000	8.1 years	$ 2.26
5.08 to 5.08	371,320	4.8 years	$ 5.08	101,320	4.8 years	$ 5.08
5.96 to 6.23	1,599,580	8.0 years	$ 5.98	301,300	6.7 years	$ 6.02
7.22 to 8.84	111,000	3.9 years	$ 7.52	42,000	3.5 years	$ 7.47
8.93 to 13.86	236,000	6.5 years	$ 11.66	94,000	3.0 years	$ 10.47
14.43 to 16.85	62,000	9.4 years	$ 15.24	—	—	$ —
18.36 to 27.15	967,500	9.3 years	$ 19.53	—	—	$ —
2.20 to 27.15	4,436,400	7.9 years	$ 8.41	675,620	6.0 years	$ 5.83

The aggregate intrinsic value of options outstanding and exercisable at December 31, 2010 was $83.5 million and $15.2 million, respectively. The aggregate intrinsic value represents the total pre-tax value (the difference between Brigham's closing stock price on the last trading day of 2010 and the exercise price, multiplied by the number of in-the-money options) that would have been received by the option holders had all option holders exercised their options on December 31, 2010. The amount of aggregate intrinsic value will change based on the fair market value of Brigham's stock.

Brigham commenced an exchange offer on July 13, 2009 pursuant to which eligible employees were offered the opportunity to exchange outstanding stock options granted prior to April 21, 2009 for new stock options. On Monday, August 10, 2009, pursuant to the exchange offer, eligible option holders tendered, and Brigham accepted for cancellation, 1,536,975 eligible stock options. After the cancellation of the options accepted by Brigham in the exchange offer, Brigham granted new stock options with an exercise price of $5.955 per share, which was the mean of the high and low sales price per share of Brigham shares as reported by The Nasdaq Global Select Market on August 10, 2009. The exchange of options resulted in incremental compensation expense of $1.3 million that is being recognized over the five year vesting period of the new options.

As of December 31, 2010 there was approximately $15.6 million of total unrecognized compensation expense related to unvested stock based compensation plans. This compensation expense is expected to be realized over the remaining vesting period of approximately 4.8 years.

Restricted Stock

During the year ended December 31, 2010, Brigham issued 105,363, restricted shares of common stock as compensation to officers and employees of Brigham. Restrictions lapsed on 20,363 of these shares in 2010, resulting in recognition of approximately $334,000 in compensation expense. Restrictions on 85,000 restricted shares lapse in 2015. As of December 31, 2010, there was approximately $2 million of total unrecognized compensation expense related to unvested restricted stock. This compensation expense is expected to be recognized, net of forfeitures, over the remaining vesting period of approximately 4 years. Brigham has assumed a 3% weighted average forfeiture rate for restricted stock to be used in calculating compensation expense. If actual forfeitures differ from the estimates, adjustments to compensation expense may be required in future periods.

The following table reflects the outstanding restricted stock awards and activity related thereto for the years ended December 31:

	Year Ended December 31, 2010			Year Ended December 31, 2009		
	Number of Shares		Weighted-Average Price	Number of Shares		Weighted-Average Price
Restricted Stock Awards:						
Restricted shares outstanding at the beginning of the year	556,990	$	7.04	593,260	$	7.58
Shares granted	105,363	$	14.45	342,574	$	4.99
Lapse of restrictions	(130,070)	$	7.71	(377,844)	$	6.02
Forfeitures	(1,400)	$	5.26	(1,000)	$	9.49
Restricted shares outstanding at the end of the year	530,883	$	8.35	556,990	$	7.04

14. Employee Benefit Plans

Brigham has adopted a defined contribution 401(k) plan for substantially all of its employees. The plan provides for Brigham matching of employee contributions to the plan, at Brigham's discretion. During 2010, 2009, and 2008, Brigham provided a base match equal to 25% of eligible employee contributions. Based on attainment of performance goals established at the beginning of each fiscal year, Brigham matched an additional 200% of eligible employee contributions made during 2010. There was no additional match for employee contributions made during 2009 and 2008. Brigham contributed approximately $1.7 million, $143,000, and $159,000 to the 401(k) plan for the years ended December 31, 2010, 2009 and 2008, respectively, to match eligible contributions by employees.

15. Related Party Transactions

During the years ended December 31, 2010, 2009 and 2008, Brigham incurred costs of approximately $9.7 million, $2.3 million, and $7.3 million, respectively, in fees for land acquisition services performed by Brigham Land Management, owned by a brother of Brigham's Chairman, President and Chief Executive Officer and its Executive Vice President — Land and Administration. Other participants in Brigham's 3-D seismic projects reimbursed Brigham for a portion of these amounts. At December 31, 2010, 2009 and 2008, Brigham had a liability recorded in accounts payable of approximately $1,000, $30,000, and $129,000, respectively, related to services performed by this company.

Mr. Harold Carter, a director of Brigham, served as a consultant to Brigham on various aspects of its business and strategic issues during 2008. Fees paid for these services by Brigham were approximately $30,000 for the year ended December 31, 2008. During each of the years ended December 31, 2009 and 2008, additional payments of approximately $2,500 and $12,000, respectively, were made for the reimbursement of certain expenses. At December 31, 2010, 2009 and 2008, there were no payables related to these services recorded by Brigham.

From time to time, in the normal course of business, Brigham has engaged a service company in which Mr. Hobart Smith, one of Brigham's current directors, owns stock and serves as a consultant. Total payments to the service company during 2010, 2009 and 2008 were $2 million, $420,000, and $1.1 million, respectively. At December 31, 2010, 2009 and 2008, Brigham owed the service company approximately $219,000, $102,000, and $76,000, respectively.

During the year ended December 31, 2010, Brigham incurred costs of $68,000 for design and development services related to the Brigham regional office located in Williston, North Dakota. The services are being provided by Decker Design & Development PC. The owner is married to a sister of Brigham's Chairman, President and Chief Executive Officer and its Executive Vice President — Land and Administration. At December 31, 2010, Brigham had a liability recorded in accounts payable of approximately $3,000 related to the services provided by this company.

16. Subsequent Events

During February 2011, Brigham amended and restated its Senior Credit Facility to provide for revolving credit borrowings up to $600 million, with an initial borrowing base of $325 million. Borrowings under the new Senior Credit Facility cannot exceed its borrowing base, which is determined at least semi-annually. Brigham also extended the maturity of its new Senior Credit Facility from July 2012 to February 2016.

17. Supplemental Cash Flow Information

Supplemental cash flow information consists of the following (in thousands):

	Year Ended December 31,		
	2010	2009	2008
Cash paid for interest, net of capitalized amounts	$ 4,726	$ 14,545	$ 12,382
Noncash investing and financing activities:			
Capitalized asset retirement obligations	814	327	412
Accrued drilling costs	45,569	(4,270)	4,927
Capitalized stock compensation	2,316	2,003	1,334

18. Other Assets and Liabilities

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

	December 31	
	2010	2009
Prepayments	$ 2,490	$ 767
Derivative assets	2,557	1,152
Other	2,749	365
	$ 7,796	$ 2,284

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

	December 31	
	2010	2009
Accrued interest	$ 6,971	$ 2,660
Other accrued liabilities	3,850	2,641
	$ 10,821	$ 5,301

BRIGHAM EXPLORATION COMPANY

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Oil and Natural Gas Exploration and Production Activities

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

Costs Incurred and Capitalized Costs

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

	December 31,		
	2010	2009	2008
Costs incurred for the year:			
Exploration (including geological and geophysical costs)	$ 20,906	$ 10,566	$ 43,229
Property acquisition	121,058	15,416	35,299
Development	273,158	54,261	110,155
	$ 415,122	$ 80,243	$ 188,683

Excluded costs for prospects are accumulated by year. Costs are reflected in the full cost pool as the drilling program is executed or as costs are evaluated and deemed impaired. Brigham anticipates these excluded costs will be included in the depletion computation over the next five years. Brigham is unable to predict the future impact on depletion rates. The following is a summary of capitalized costs (in thousands) excluded from depletion at December 31, 2010 by year incurred.

	December 31,			Prior	
	2010	2009	2008	Years	Total
Property acquisition	$ 79,308	$ 5,680	$ 11,851	$ 2,775	$ 99,614
Exploration (including geological and geophysical costs)	1,679	37	3,256	13,146	18,118
Drilling	50,981	—	—	—	50,981
Capitalized interest	7,876	3,902	1,902	540	14,220
Total	$ 139,844	$ 9,619	$ 17,009	$ 16,461	$ 182,933

Oil and Natural Gas Reserves and Related Financial Data

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

BRIGHAM EXPLORATION COMPANY

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) — (Continued)

Oil and Natural Gas Reserve Data

The following tables present estimates of Brigham's proved oil and natural gas reserves prepared by independent petroleum consultants. Brigham emphasizes reserves are approximations and are expected to change as additional information becomes available. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

	Oil (MBbls)	Natural Gas (MMcf)
Proved reserves at December 31, 2007	5,593	106,643
Revisions of previous estimates	413	(7,834)
Extensions, discoveries and other additions	1,637	3,866
Production	(578)	(7,996)
Proved reserves at December 31, 2008	7,065	94,679
Revisions of previous estimates	2,055	(28,742)
Extensions, discoveries and other additions	8,354	6,367
Sales of mineral in place	(37)	(13)
Production	(814)	(5,892)
Proved reserves at December 31, 2009	16,623	66,399
Revisions of previous estimates (a)	3,588	(856)
Extensions, discoveries and other additions (b)	34,523	27,045
Purchase of mineral in place	219	211
Sales of mineral in place	(528)	(412)
Production	(2,216)	(4,562)
Proved reserves at December 31, 2010	52,209	87,825
Proved developed reserves at December 31:		
2007	3,321	49,367
2008	3,583	41,928
2009	5,342	29,178
2010	17,522	36,537

(a) Revisions of previous estimates include performance and technical revisions of 3,619 MBoe, economic revisions of 895 MBoe, interest trades of (255) MBoe, and elimination of PUD reserves that will not be developed within 5 years of (813) MBoe.

(b) Extensions, discoveries and other additions include discoveries and associated PUD's of 39,030 MBoe, primarily in the Williston Basin.

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

Standardized Measure of Discounted Future Net Cash Inflows and Changes Therein

The following table presents a standardized measure of discounted future net cash inflows (in thousands) relating to proved oil and natural gas reserves. For 2008, future cash flows were computed by applying year-end prices of crude oil and natural gas relating to Brigham's proved reserves to the estimated year-end quantities of those reserves. Under new rules issued by the Securities and Exchange Commission, the estimated future net cash flows at December 31, 2010 and 2009 were determined using a 12-month average price. Future price changes were considered only to the extent provided by contractual agreements in existence at year-end. Future production and development costs were computed by estimating those expenditures expected to occur in developing and producing the proved oil and natural gas reserves at the end of the year, based on year-end costs. Actual future cash inflows may vary considerably, and the standardized measure does not necessarily represent the fair value of Brigham's oil and natural gas reserves.

	December 31, 2010	2009	2008
Future cash inflows	$ 4,233,003	$ 1,158,260	$ 899,745
Future production costs	(1,117,690)	(330,837)	(206,640)
Future development costs	(770,356)	(266,733)	(160,304)
Future income tax expense	(619,145)	(32,493)	(32,152)
Future net cash inflows	1,725,812	528,197	500,649
10% annual discount for estimated timing of cash flows	(859,699)	(281,721)	(221,353)
Standardized measure of discounted future net cash flows	$ 866,113	$ 246,476	$ 279,296

Prices were adjusted to reflect applicable transportation and quality differentials on a well-by-well basis to arrive at realized sales prices used to estimate Brigham's reserves. The prices used for Brigham's reserve estimates were as follows:

	Oil (Bbl)	Natural Gas (MMbtu)
December 31, 2010	$ 79.43	$ 4.38
December 31, 2009	61.18	$ 3.87
December 31, 2008	44.60	$ 5.71

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

	December 31, 2010	2009	2008
Beginning of period	$ 246,476	$ 279,296	$ 394,514
Sales of oil and natural gas produced, net of production costs	(143,169)	(48,439)	(107,144)
Previously estimated development costs incurred during the period	69,829	16,574	51,494
Extensions and discoveries	643,526	75,803	30,175
Net change of prices and production costs	213,101	(41,750)	(184,497)
Change in future development costs	(39,841)	6,874	(28,901)
Changes in production rates (timing)	18,296	(17,557)	(2,201)
Revisions of previous quantity estimates	84,417	(41,726)	(16,436)
Accretion of discount	25,430	28,722	49,130
Change in income taxes	(234,529)	99	88,868
Purchases of reserves in place	6,688	—	—
Sales of reserves in place	(9,877)	(591)	—
Other	(14,234)	(10,829)	4,294
End of period	$ 866,113	$ 246,476	$ 279,296

BRIGHAM EXPLORATION COMPANY

SUPPLEMENTAL QUARTERLY FINANCIAL INFORMATION

Quarterly Financial Data (Unaudited)

	Year Ended December 31, 2010			
	Quarter 1	**Quarter 2**	**Quarter 3**	**Quarter 4**
Revenue	$ 32,573	$ 44,930	$ 36,610	$ 55,609
Operating income (loss)	13,081	19,336	9,364	18,663
Net income (loss)*	11,315	18,473	(676)	13,784
Net income (loss) per share:				
Basic	$ 0.11	$ 0.16	$ (0.01)	$ 0.12
Diluted	$ 0.11	$ 0.16	$ (0.01)	$ 0.12

	Year Ended December 31, 2009			
	Quarter 1	**Quarter 2**	**Quarter 3**	**Quarter 4**
Revenue	$ 18,486	$ 10,514	$ 19,867	$ 21,477
Operating income (loss)*	(115,152)	(2,787)	4,750	4,273
Net income (loss)*	(119,071)	(6,960)	491	2,548
Net income (loss) per share:				
Basic	$ (2.60)	$ (0.12)	$ 0.01	$ 0.03
Diluted	$ (2.60)	$ (0.12)	$ 0.01	$ 0.03

* Net income (loss) includes the impact from the loss on early redemption of Senior Notes in the amount of $10.9 million for the third quarter of 2010. Operating income (loss) and Net income (loss) include the impact from the writedown of the net capitalized costs of Brigham's oil and gas properties in the amounts of $114.8 million for the first quarter of 2009.

INDEX TO EXHIBITS

Number		Description
3.1	—	Certificate of Incorporation (filed as Exhibit 3.1 to Brigham's Registration Statement on Form S-1 (Registration No. 333-22491) and incorporated herein by reference)
3.2	—	Certificates of Amendment of Certificate of Incorporation (filed as Exhibit 3.1.1 to Brigham's Registration Statement on Form S-3 (Registration No. 333-37558) and incorporated herein by reference)
3.3	—	Bylaws, as amended through May 28, 2009 (filed as Exhibit 3.5 to Brigham's Current Report on Form 8-K (filed May 28, 2009) and incorporated herein by reference)
3.4	—	Certificate of Amendment of Certificate of Incorporation of Brigham Exploration Company dated June 14, 2006, (filed as Exhibit 3.4 to Brigham's Annual Report on Form 10-K for the year ended December 31, 2008 and incorporated herein by reference)
3.5	—	Certificate of Amendment of Certificate of Incorporation of Brigham Exploration Company dated October 7, 2009 (filed as Exhibit 3.5 to Brigham's Current Report on Form 8-K (filed October 13, 2009) and incorporated herein by reference)
4.1	—	Form of Common Stock Certificate (filed as Exhibit 4.1 to Brigham's Registration Statement on Form S-1 (Registration No. 333-22491) and incorporated herein by reference)
4.2	—	Certificate of Designations of Series A Preferred Stock (Par Value $.01 Per Share) of Brigham Exploration Company filed October 31, 2000 (filed as Exhibit 4.1 to Brigham's Current Report on Form 8-K, as amended (filed November 8, 2000) and incorporated herein by reference)
4.3	—	Certificate of Amendment of Certificate of Designations of Series A Preferred Stock (Par Value $.01 Per Share) of Brigham Exploration Company, filed March 2, 2001 (filed as Exhibit 4.2.1 to Brigham's Annual Report on Form 10-K for the year ended December 31, 2000 and incorporated herein by reference)
4.4	—	Certificate of Elimination of Certificate of Designations of Series A Preferred Stock (Par Value $.01 Per Share) of Brigham Exploration Company, filed August 9, 2010 (filed as Exhibit 3.7 to Brigham's Current Report on Form 8-K (filed August 10, 2010) and incorporated herein by reference)
4.5	—	Certificate of Designations of Series B Preferred Stock (Par Value $.01 Per Share) of Brigham Exploration Company filed December 20, 2002 (filed as Exhibit 4.4 to Brigham's Annual Report on Form 10-K for the year ended December 31, 2002 and incorporated herein by reference)
4.6	—	Certificate of Elimination of Certificate of Designations of Series B Preferred Stock of Brigham Exploration Company, dated June 4, 2004, (filed as Exhibit 99.2 to Brigham's Current Report on Form 8-K (filed July 20, 2004) and incorporated herein by reference)
4.7	—	Certificate of Designations of Series C Junior Participating Preferred Stock of Brigham Exploration Company effective as of December 10, 2008 (filed as Exhibit 3.1 to Brigham's Current Report on Form 8-K (filed December 11, 2008) and incorporated herein by reference)
4.8	—	Certificate of Elimination of Certificate of Designations of Series C Junior Participating Preferred Stock of Brigham Exploration Company effective March 9, 2010 (filed as Exhibit 3.6 to Brigham's Current Report on Form 8-K (filed March 15, 2010) and incorporated herein by reference)
4.9	—	First Supplemental Indenture, dated September 27, 2010, among the Company, the Guarantors and Wells Fargo Bank, National Association, as Trustee (filed as Exhibit 4.16 to Brigham's Current Report on Form 8-K (filed October 1, 2010) and incorporated herein by reference)
4.10	—	Indenture, dated September 27, 2010, among the Company, the Guarantors and Wells Fargo Bank, National Association, as Trustee (filed as Exhibit 4.17 to Brigham's Current Report on Form 8-K (filed October 1, 2010) and incorporated herein by reference)

Number		Description
4.11	—	Rule 144A 8 3/4% Senior Note due 2018 and Notation of Guarantee (filed as Exhibit 4.18 to Brigham's Current Report on Form 8-K (filed October 1, 2010) and incorporated herein by reference)
4.12	—	Regulation S 8 3/4% Senior Note due 2018 and Notation of Guarantee (filed as Exhibit 4.19 to Brigham's Current Report on Form 8-K (filed October 1, 2010) and incorporated herein by reference)
10.1	—	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. (filed as Exhibit 10.1.4 to Brigham's Annual Report on Form 10-K for the year ended December 31, 1998 and incorporated herein by reference)
10.2*	—	Form Change of Control Agreement dated as of September 20, 1999 between Brigham Exploration Company and certain Officers (filed as Exhibit 10.3 to Brigham's Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 1999 and incorporated by reference herein)
10.3	—	Fourth Amended and Restated Credit Agreement, dated June 29, 2005 between Brigham Oil & Gas, L.P., Bank of America, N.A., The Royal Bank of Scotland plc, BNP Paribas and Banc of America Securities LLC. (filed as Exhibit 10.1 to Brigham's Quarterly Report on Form 10-Q for the fiscal quarter ended June 30, 2005 and incorporated herein by reference)
10.4	—	Resignation of Agent, Appointment of Successor Agent and Assignment of Security Instruments dated June 29, 2005 by and among Brigham Oil & Gas, L.P., Sociétè Generale and Bank of America, N.A. (filed as Exhibit 10.2 to Brigham's Quarterly Report on Form 10-Q for the fiscal quarter ended June 30, 2005 and incorporated herein by reference)
10.5	—	First Amendment to Fourth Amended and Restated Credit Agreement, between Brigham Exploration Company and the banks named therein, dated April 10, 2006 (filed as Exhibit 10.3 to Brigham's Current Report on Form 8-K, as amended (filed April 24, 2006) and incorporated herein by reference)
10.6	—	Second Amendment to Fourth Amended and Restated Credit Agreement, between Brigham Exploration Company and the banks named therein, dated March 27, 2007 (filed as Exhibit 10.3 to Brigham's Current Report on Form 8-K (filed on April 13, 2007) and incorporated in by reference)
10.7*	—	Form of the Amended and Restated Indemnity Agreement (filed as Exhibit 99.1 to Brigham's Current Report on Form 8-K, as amended (filed December 5, 2006), and incorporated herein by reference)
10.8	—	Agreement Relating to Voting of Shares dated July 31, 2008, between Brigham Exploration Company and DLJ Merchant Banking Partners III, L.P., DLJ Offshore Partners III, C.V., DLJ Offshore Partners III-1, C.V., DLJ Offshore Partners III-2, C.V., DLJ MB Partners III GmbH & Co. KG, Millennium Partners II, L.P., MBP III Plan Investors, L.P., DLJ ESC II, L.P. and DLJMB Funding III, Inc. (filed as Exhibit 10.42 to Brigham's Current Report on Form 8-K (filed August 5, 2008) and incorporated herein by reference)
10.9	—	Third Amendment to the Fourth Amended and Restated Credit Agreement dated as of November 7, 2008 (filed as Exhibit 10.43 to Brigham's Current Report on Form 8-K (filed November 12, 2008) and incorporated herein by reference)
10.10*	—	Amendment to the 1997 Incentive Plan, dated March 9, 2010 (filed as Exhibit 10.46 to Brigham's Current Report on Form 8-K (filed March 15, 2010) and incorporated herein by reference)
10.11*	—	Form of Restricted Stock Agreement under the 1997 Incentive Plan of Brigham Exploration Company (filed as Exhibit 10.45 to Brigham's Current Report on Form 8-K (filed December 29, 2008) and incorporated herein by reference)

Number	Description
10.12*	— Form of Option Agreement (Non-Qualified Stock Option) under the 1997 Incentive Plan of Brigham Exploration Company (filed as Exhibit 10.46 to Brigham's Current Report on Form 8-K (filed December 29, 2008) and incorporated herein by reference)
10.13*	— Form of Option Agreement (Incentive Option) under the 1997 Incentive Plan of Brigham Exploration Company (filed as Exhibit 10.47 to Brigham's Current Report on Form 8-K (filed December 29, 2008) and incorporated herein by reference)
10.14*	— Brigham Exploration Company 1997 Director Stock Option Plan (as amended effective January 1, 2009) (filed as Exhibit 10.48 to Brigham's Current Report on Form 8-K (filed December 29, 2008) and incorporated herein by reference)
10.15*	— Form of Non-Qualified Stock Option Agreement under the 1997 Director Stock Option Plan (filed as Exhibit 10.49 to Brigham's Current Report on Form 8-K (filed December 29, 2008) and incorporated herein by reference)
10.16*	— Form of Amendment to the Change of Control Agreement (filed as Exhibit 10.50 to Brigham's Current Report on Form 8-K (filed December 29, 2008) and incorporated herein by reference)
10.17*	— Amendment to the Employment Agreement between the Company and Ben M. Brigham dated as of December 23, 2008 (filed as Exhibit 10.51 to Brigham's Current Report on Form 8-K (filed December 29, 2008) and incorporated herein by reference)
10.18	— Confirmation of Notice of Termination of Consulting Agreement with Harold D. Carter, between Brigham Oil & Gas, L.P. and Harold D. Carter, effective as of January 1, 2009 (filed as Exhibit 10.41 to Brigham's Quarterly Report on Form 10-Q for the fiscal quarter ended March 31, 2009 and incorporated herein by reference)
10.19*	— 1997 Incentive Plan Amendment to Option Agreements, effective as of April 22, 2009 (filed as Exhibit 10.42 to Brigham's Quarterly Report on Form 10-Q for the fiscal quarter ended March 31, 2009 and incorporated herein by reference)
10.20	— Fourth Amendment to the Fourth Amended and Restated Credit Agreement dated as of May 13, 2009 (filed as Exhibit 10.43 to Brigham's Current Report on Form 8-K (filed May 28, 2009) and incorporated herein by reference)
10.21	— Fifth Amendment to the Fourth Amended and Restated Credit Agreement dated as of July 24, 2009 (filed as Exhibit 10.45 to Brigham's Current Report on Form 8-K (filed July 28, 2009) and incorporated herein by reference)
10.22*	— Form of Non-Qualified Stock Option Agreement (filed as Exhibit 10.49 to Brigham's Quarterly Report on Form 10-Q for the fiscal quarter ended June 30, 2009) and incorporated herein by reference)
10.23*	— Form of Non-Qualified Stock Option Agreement under the 1997 Director Stock Option Plan (filed as Exhibit 10.3 to Brigham's Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2009 and incorporated herein by reference)
10.24*	— Form of Non-Qualified Stock Option Agreement (filed as Exhibit 10.4 to Brigham's Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2009 and incorporated herein by reference)
10.25*	— Form of Amendment to Non-Qualified Stock Option Agreements (filed as Exhibit 10.5 to Brigham's Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2009 and incorporated herein by reference)
10.26*	— Amendment to Brigham Exploration Company 1997 Director Stock Option Plan, effective as of September 23, 2009 (filed as Exhibit 10.6 to Brigham's Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2009 and incorporated herein by reference)
10.27*	— Amendment to Non-Qualified Stock Option Agreements under the 1997 Director Stock Option Plan, effective as of September 23, 2009 (filed as Exhibit 10.7 to Brigham's Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2009 and incorporated herein by reference)

Number	Description
10.28 —	Sixth Amendment and Consent to the Fourth Amended and Restated Credit Agreement dated as of May 28, 2010 between the Company and the banks named therein (filed as Exhibit 10.47 to Brigham's Current Report on Form 8-K (filed June 3, 2010) and incorporated herein by reference)
10.29 —	Registration Rights Agreement, dated September 27, 2010, among the Company, the Guarantors and the Initial Purchasers (filed as Exhibit 4.20 to Brigham's Current Report on Form 8-K (filed October 1, 2010) and incorporated herein by reference)
10.30 —	Seventh Amendment to the Fourth Amended and Restated Credit Agreement dated as of September 10, 2010 between the Company and the banks named therein (filed as Exhibit 10.48 to Brigham's Current Report on Form 8-K (filed September 13, 2010) and incorporated herein by reference)
10.31 —	Purchase Agreement dated September 16, 2010 among the Company, the Guarantors and the Initial Purchasers. (filed as Exhibit 10.49 to Brigham's Current Report on Form 8-K (filed September 20, 2010) and incorporated herein by reference)
12.1† —	Statement Regarding Computation of Ratios
21† —	Subsidiaries of the Registrant
23.1† —	Consent of KPMG LLP, Independent Registered Public Accounting Firm
23.2† —	Consent of Cawley, Gillespie & Associates, Inc.
31.1† —	Certification of Chief Executive Officer pursuant to Sec. 302 of the Sarbanes-Oxley Act of 2002
31.2† —	Certification of Chief Financial Officer pursuant to Sec. 302 of the Sarbanes-Oxley Act of 2002
32.1† —	Certification of Chief Executive Officer pursuant to 18 U.S.C. SECTION 1350
32.2† —	Certification of Chief Financial Officer pursuant to 18 U.S.C. SECTION 1350
99.1† —	Report of Cawley, Gillespie & Associates, Inc.

---

* Management contract or compensatory plan.

† Filed herewith

Exhibit 31.1

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13a-14(a) OF THE
SECURITIES EXCHANGE ACT OF 1934**

I, Ben M. Brigham, certify that:

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

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2011

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

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13a-14(a) OF THE
SECURITIES EXCHANGE ACT OF 1934

I, Eugene B. Shepherd, Jr, certify that:

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

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2011

/s/ EUGENE B. SHEPHERD, JR.
Eugene B. Shepherd, Jr.
Executive Vice President and Chief Financial Officer

Exhibit 32.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Brigham Exploration Company (the "Company") on Form 10-K for the period ending December 31, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Ben M. Brigham, President, Chief Executive Officer and Chairman of the Board of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 28, 2011

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

This certification shall not be deemed to be "filed" for the purpose of Section 18 of the Securities Exchange Act of 1934, as amended, and will not be incorporated by reference into any registration statement filed under the Securities Act of 1933, as amended, unless specifically identified therein as being incorporated therein by reference.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to Brigham Exploration Company and will be retained by Brigham Exploration Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Brigham Exploration Company (the "Company") on Form 10-K for the period ending December 31, 2010 as filed with the Securities and Exchange Commission on the date hereof ("the "Report"), I, Eugene B. Shepherd, Jr., Executive Vice President and Chief Financial Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 28, 2011

/s/ EUGENE B. SHEPHERD, JR.
Eugene B. Shepherd, Jr.
Executive Vice President and
Chief Financial Officer

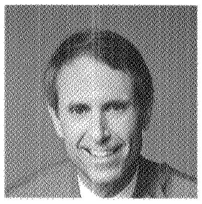
This certification shall not be deemed to be "filed" for the purpose of Section 18 of the Securities Exchange Act of 1934, as amended, and will not be incorporated by reference into any registration statement filed under the Securities Act of 1933, as amended, unless specifically identified therein as being incorporated therein by reference.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided Brigham Exploration Company and will be retained by Brigham Exploration Company and furnished to the Securities and Exchange Commission or its staff upon request.

THE BRIGHAM MANAGEMENT TEAM

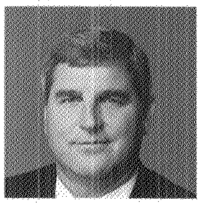
Ben "Bud" M. Brigham
President, CEO &
Chairman of the Board

Eugene B. Shepherd, Jr.
Executive Vice President
& Chief Financial Officer

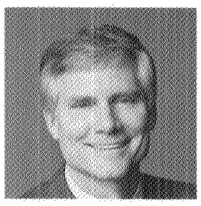


David T. Brigham
Executive Vice President
of Land & Administration
& Director

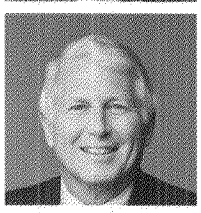
A. Lance Langford
Executive Vice President
of Operations



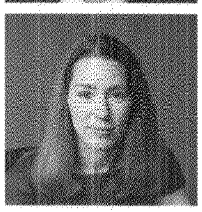
Jeffery E. Larson
Executive Vice President
of Exploration



Malcom O. Brown
Vice President
& Controller



Kari A. Potts
General Counsel &
Corporate Secretary



INFORMATION REQUESTS

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

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 "Item 1.A.Risk Factors" and "Disclosure Regarding Forward Looking Statements" in Brigham's Form 10-K included in this Annual Report and Brigham's other filings with the Securities and Exchange Commission.

ADDITIONAL INFORMATION

Drilling locations have not been risked by Company management. Actual locations drilled and quantities that may be ultimately recovered from the Company's interests could differ substantially. "De-risked" core development acreage and related well locations in the Williston Basin refers to acreage and locations that the Company believes the relative geological risks with recovery has been reduced as a result of drilling operations to date. However, only a small portion of such acreage and locations has been attributed proved undeveloped reserves, and ultimate recovery from such acreage and locations remains subject to all the recovery risks applicable to other acreage.

annual meeting

9:00 am CDT on June 21, 2011
at our regional office in Williston, ND

14613 Brigham Drive
Williston, North Dakota 58801
Phone: 701.875.3300

board of directors

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

David T. Brigham
Executive Vice President of
Land & Administration & Director

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

Stephen C. Hurley
President of Hunt Oil Company

Stephen P. Reynolds
Former Partner, General Atlantic Partners, LLC

Hobart A. Smith
Consultant for Schlumberger

Scott W. Tinker, Ph.D.
Director, Bureau of Economic Geology &
State Geologist of Texas; Professor, Allday
Endowed Chair, Jackson School of Geosciences;
The University of Texas at Austin

corporate information

Independent Auditors
KPMG LLP
Dallas, Texas

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

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

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

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

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

NASDAQ: BEXP

6300 BRIDGE POINT PKWY. BUILDING 2, SUITE 500. AUSTIN, TX 78730. (P) 512.427.3300. (F) 512.427.3400
WWW.BEXP3D.COM