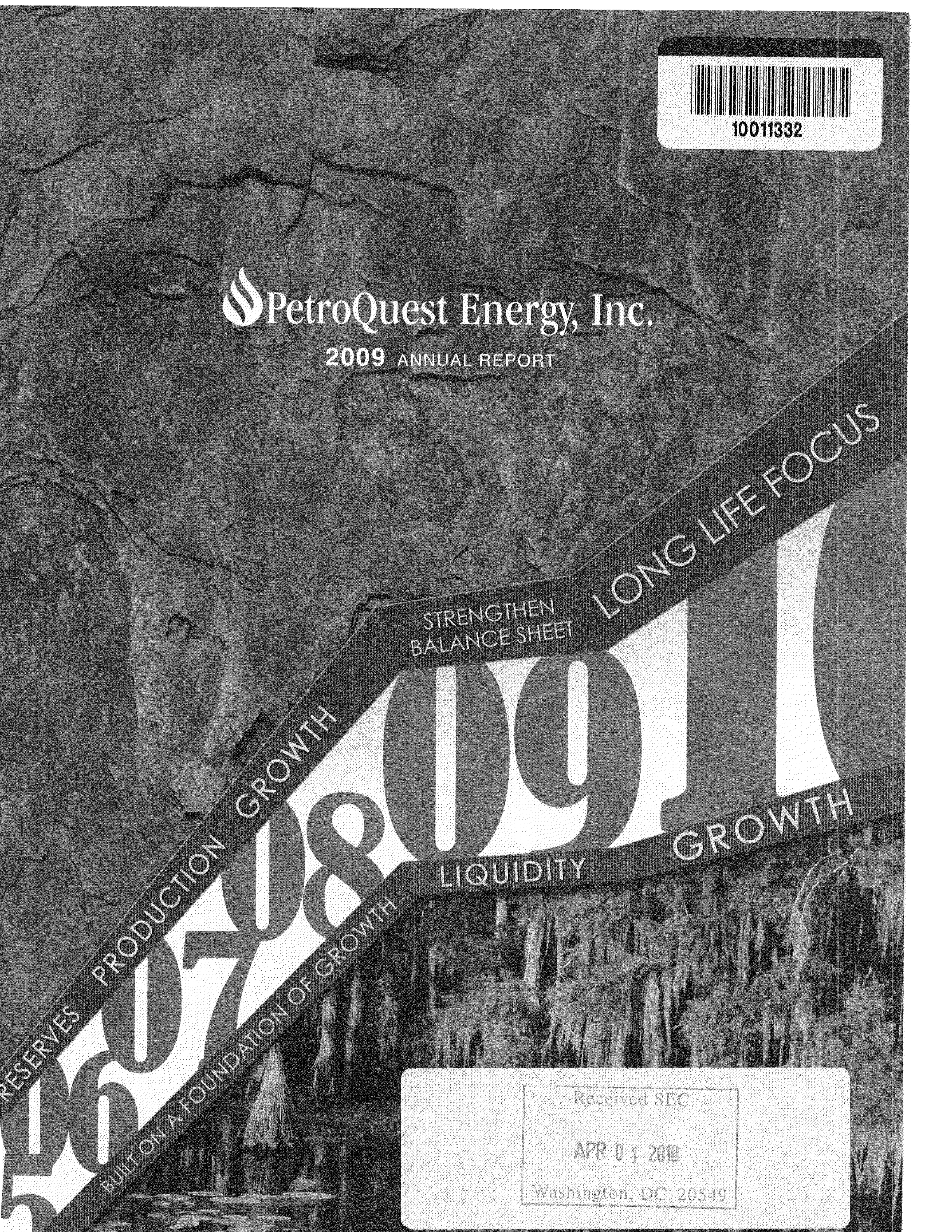
PetroQuest Energy, Inc.

2009 ANNUAL REPORT



Corporate Profile

PetroQuest Energy is a diversified exploration and production company with a long-term track record of delivering value to stockholders by focusing on low-risk, repeatable operations in long-life basins and resource trends such as the world-class Woodford and Fayetteville Shale plays.

1999-2009: A Decade to Remember

Since writing my first letter to you for our 1999 Annual Report, I've had to write to you about:

- **Entering the new millennium in 2000;**
- **The attacks on the World Trade Center;**
- **Wars in Iraq and Afghanistan;**
- **Hurricanes Katrina, Rita, Gustav and Ike;**
- **The continuous rise and fall of natural gas prices;**
- **Expansion into East Texas, Oklahoma and Arkansas;**
- **A near cataclysmic destruction of the world financial system;**
- **Production and reserve growth.**

The constant through it all has been the hard work and dedication of the people at PetroQuest. We've been up, and we've been down. But we've persevered and thrived. We are here, but many financial institutions, oil companies and small businesses are gone. Despite the daily doom and gloom often broadcast by the press and repeated by our political leaders, we're still here drilling and producing, and America keeps selling, building and expanding as it has done since this country's founding more than 233 years ago. Now is the time for action and hard work rather than hand-wringing.

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The Annual Meeting will be held at 9:00 A.M. CDT on May 12, 2010, at the City Club at River Ranch at 221 Elysian Fields Dr., Lafayette, LA, 70508.

Financial & Operational Highlights

	2004 Annual	2005 Annual	2006 Annual	2007 Annual	2008 Annual	2009 Q1	2009 Q2	2009 Q3	2009 Q4	2009 Annual	5-Year CAGR
Production											
Natural Gas, MMcf	9,305	12,058	21,528	24,966	29,708	9,047	7,728	7,169	6,654	30,598	27%
Crude Oil, MBbl	818	665	695	1,080	681	175	139	137	149	600	NM
Natural Gas, MMcfe	14,216	16,051	25,697	31,444	33,792	10,096	8,561	7,992	7,550	34,199	19%
Financial ($ Thousands, except per share amounts)											
Total Revenues	$ 84,595	$ 120,552	$ 199,520	$ 262,334	$ 313,958	$ 59,449	$ 55,261	$ 50,254	$ 53,911	$ 218,875	21%
Net Income (Loss)	16,348	21,417	23,986	40,619	(96,960)	(65,677)	9,033	5,740	(39,286)	(90,190)	NM
Preferred Stock Dividends	--	--	--	1,374	5,140	1,280	1,287	1,287	1,286	5,140	NM
Net Income (Loss) Available to Common Stockholders	$ 16,348	$ 21,417	$ 23,986	$ 39,245	$ (102,100)	$ (66,957)	$ 7,746	$ 4,453	$ (40,572)	$ (95,330)	NM
Per Common Share:											
Basic	$ 0.37	$ 0.46	$ 0.50	$ 0.82	$ (2.08)	$ (1.36)	$ 0.15	$ 0.07	$ (0.66)	$ (1.72)	NM
Diluted	$ 0.35	$ 0.44	$ 0.49	$ 0.79	$ (2.08)	$ (1.36)	$ 0.15	$ 0.07	$ (0.66)	$ (1.72)	NM

Year-Over-Year Review

	2004	2005	2006	2007	2008	2009	5-Year CAGR
Reserves							
Natural Gas, MMcf	79,069	109,115	118,153	142,468	172,186	167,361	16%
Crude Oil, MBbl	3,714	3,642	2,731	2,342	2,201	1,931	-12%
Natural Gas, MMcfe	101,353	130,967	134,539	156,520	185,392	178,947	12%
Percent Developed	68%	69%	72%	69%	73%	62%	
Percent Natural Gas	78%	83%	88%	91%	93%	94%	
Percent Gulf Coast	59%	39%	30%	29%	32%	23%	
Future Undiscounted Net Cash Flows, $000s	$ 443,487	$ 861,689	$ 516,013	$ 779,395	$ 466,449	$ 272,271	-9%
SEC PV-10, Before Taxes, $000s	$ 326,267	$ 639,734	$ 384,313	$ 540,651	$ 327,193	$ 176,995	-12%
Commodity Prices							
PetroQuest Realized, Natural Gas, $/Mcf	$ 5.99	$ 7.47	$ 7.04	$ 7.21	$ 8.16	$ 5.80	
Henry Hub Cash Market Average, Natural Gas, $/Mcf	6.15	8.89	6.73	6.97	8.89	3.94	Source: Bloomberg
PetroQuest Realized, Crude Oil, $/Bbl	35.31	45.76	60.91	70.52	97.49	68.57	
WTI (Cushing) Spot Average, Crude Oil, $/Bbl	41.48	56.59	66.09	72.23	99.92	61.99	Source: Bloomberg
PetroQuest Realized, Natural Gas Equivalent, $/Mcfe	5.95	7.51	7.54	8.15	9.13	6.39	
Statistics							
Reserve Replacement, Excluding Revisions, %	220%	337%	152%	132%	220%	115%	
6-Year Reserve Replacement, Excluding Revisions, %						180%	
Finding & Development Costs, Excluding Revisions, $/Mcfe	$ 2.77	$ 3.62	$ 4.36	$ 5.82	$ 4.82	$ 1.50	
6-Year Finding & Development Costs, Excluding Revisions, $/Mcfe						$ 3.96	
Per Unit Analysis, $/Mcfe							
Total Revenues	$ 5.95	$ 7.51	$ 7.76	$ 8.34	$ 9.29	$ 6.40	1%
Lease Operating Expense and Production Taxes	1.04	1.54	1.61	1.27	1.69	1.26	4%
Gas Gathering Costs	--	0.08	0.14	0.13	0.07	0.01	NM
Gross Operating Margin	4.91	5.89	6.01	6.94	7.53	5.13	1%
Interest Expense	0.20	0.77	0.56	0.43	0.28	0.37	13%
General and Administrative	0.44	0.46	0.59	0.67	0.69	0.55	5%
Preferred Stock Dividends	--	--	--	0.04	0.15	0.15	NM
Gross Cash Margin	$ 4.27	$ 4.66	$ 4.86	$ 5.80	$ 6.41	$ 4.06	-1%

Letter to Stockholders

2009 Overview

How did 2009 shape the future of PetroQuest? In many ways, 2009 was a year of transformation for PetroQuest Energy. For several years we have communicated to the market and our stockholders that we have been transitioning from a pure Gulf Coast operator to a diversified resource company, and we continued this strategy in 2009. But in the context of overall macroeconomic conditions last year, we deliberately slowed the pace of growth simply in recognition of the economic realities our industry faced. Continuing volatility in the natural gas markets, along with overall uncertainty in the broader economy, made it clear that 2009 was a unique period during which it made strategic sense to slow our operational activity given the lack of clear direction in the market. Instead of drilling through a period of low natural gas prices, we determined that the best course of action in 2009 was to focus on strengthening our balance sheet and improving liquidity, whereas in previous years we concentrated on turning the drillbit to the right. Ultimately, a natural gas company has to drill wells, but I decided that the best interests of the Company and our shareholders would be served by taking a strategic pause to pay down debt given the reduced project returns we experienced with low natural gas prices during the first three quarters of the year.

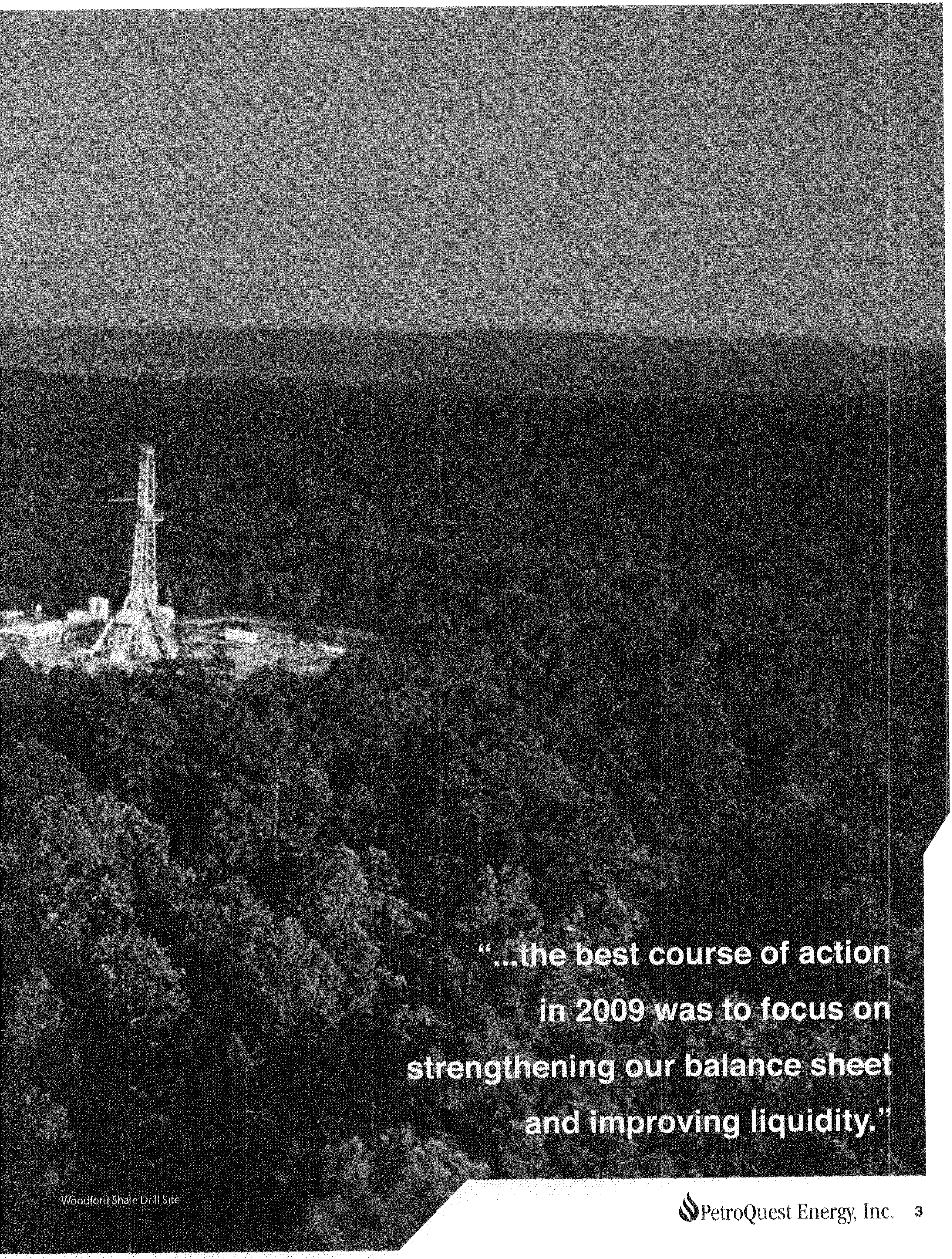
Eventually, gradual improvements in natural gas markets reflected the positive direction of the overall economy, which allowed us to maintain a modest level of operational activity during the year by drilling or participating in 15 Woodford wells and 65 horizontal Fayetteville wells.

Last year, I emphasized that I believe PetroQuest's multi-year growth is the result of applying lessons learned to the ever-present challenges we face in our industry today. In view of continuing market volatility and the unprecedented economic headwinds we experienced in 2009, it bears repeating this year that our guiding principles to which we adhere are:

- Manage growth with an established strategy of balancing exploration, development and acquisitions;
- Build a company with assets that provide stable cash flow from reliable development drilling and effective management of operating costs;
- Retain a high level of operatorship so that we can manage our own pace of growth, rather than having someone else manage it for us; and
- Focus on long-term opportunities.

Adherence to these values in executing our everyday business operations during 2009 saw PetroQuest through some of the most difficult economic and financial challenges in our Company's, and indeed our nation's, history. We demonstrated in 2009 that our principles, coupled with the superb performance and unrivaled dedication of our people, not only allowed us to survive when many other companies faltered, but placed us in a position to accelerate activity and return to the growth theme which has distinguished PetroQuest from its competitors for many years. I think it is validation of the strength of our assets that we were able to continue generating cash flow in 2009 to address our highest priority, liquidity, while maintaining production levels and selective drilling to hold our leases. In spite of significantly reducing activity in 2009, we experienced only a slight decline in reserves for the year, while at the same time modestly increased production.

I believe PetroQuest remains a unique opportunity for investors given that we are one of a select few companies who maintained essentially flat production during a sustained period of reduced drilling through a $300 million reduction in capital expenditures.



Woodford Shale Drill Site

1999-2009

Prioritizing Strength and Stability

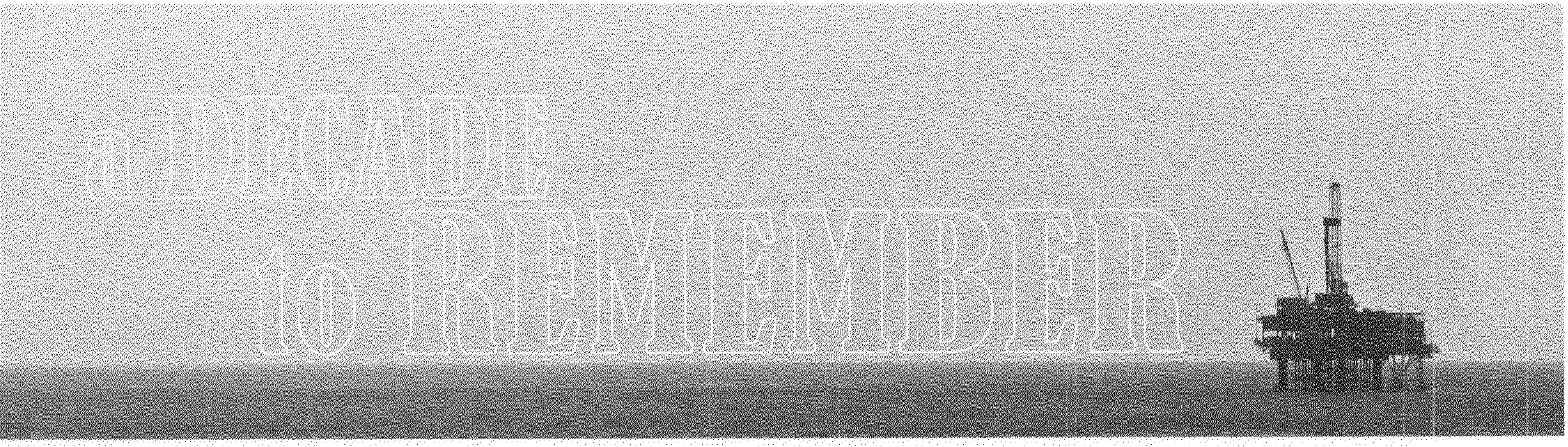
Few people, if any, predicted either the depth of the financial crisis or its apparently short duration relative to previous downturns. I know uncertainty about the global economy crept into the energy investment community as many funds faced redemption requests, hedge fund asset flows turned negative, and the broader market experienced sell-offs of unprecedented magnitude. I believe these external factors greatly contributed to the decline of our stock price to a level not seen since 2003. Fortunately, the stock price moved higher through the remainder of 2009 into 2010. What I would like to emphasize is that both our executive management team and I are bullish about our Company; the low price of our stock represented a unique opportunity for investors to buy PetroQuest stock because of the fundamental strength of the Company and the capability of our team to deliver positive results at all levels. The Company's senior management team, like each of you, continues to hold PetroQuest stock; insiders own approximately 17% of the shares outstanding. We remain convinced that the quality of our assets and our strategic decisions will allow us to return to the growth theme in 2010.

Respectable Results in Challenging Times

The new Securities and Exchange Commission (SEC) guidelines which require companies to use average commodity prices throughout the year to determine the value of proved reserves took effect on December 31, 2009. Under the new guidelines, PetroQuest ended 2009 with 179 Bcfe of proved reserves valued at a pre-tax PV-10 value of $177 million based on the average benchmark NYMEX prices for gas of $3.87 per Mcf and $61.18 per barrel for the twelve months of 2009. Historically, our industry has long advocated a change to average pricing, and there is a certain irony that in the first year these new rules are in force we experienced lower average commodity prices than in prior years.

Despite our 2009 proved reserves being slightly lower than in 2008, the 2009 reserves still represent a Company record for the second-highest reserve values in our history. 88% of our proved reserves are natural gas and 77% of our reserves are located in long-lived basins, up from 68% last year. This is further indication of the success of our transformational strategy. Importantly, 62% of our reserves are proved developed, and we still have a total drilling inventory of over 4,500 locations in our project portfolio. We have many opportunities to grow the company and much work ahead in 2010 and beyond.

Given our focus on strengthening the balance sheet, we reduced our revolver debt by $101 million from $130 million in 2008 to $29 million at the end of 2009, while our oil and gas revenues in 2009 were $219 million, and EBITDA was $144 million. Since year-end, we have paid back an additional $19 million of bank debt and we can say we have accomplished our goal of strengthening



the balance sheet. Very few, if any, small cap independent exploration and production companies can state they reduced capital expenditures by 84%, reduced debt by 78%, and maintained flat production with only a modest decrease in reserves. I am proud of each and every member of the PetroQuest team who contributed to this remarkable success story. In our business, successful companies are normally associated solely with production and reserve growth, which we have consistently delivered. However, during an economic downdraft like the one experienced these past two years, I think our company's success can also be measured by our deliberate efforts to strengthen our financial health, without resorting to large-scale asset divestitures. Although we did sell 3 Bcfe of reserves, this makes our modestly lower reserves at the end of 2009 that much more remarkable.

Outlook: 2010 and Beyond

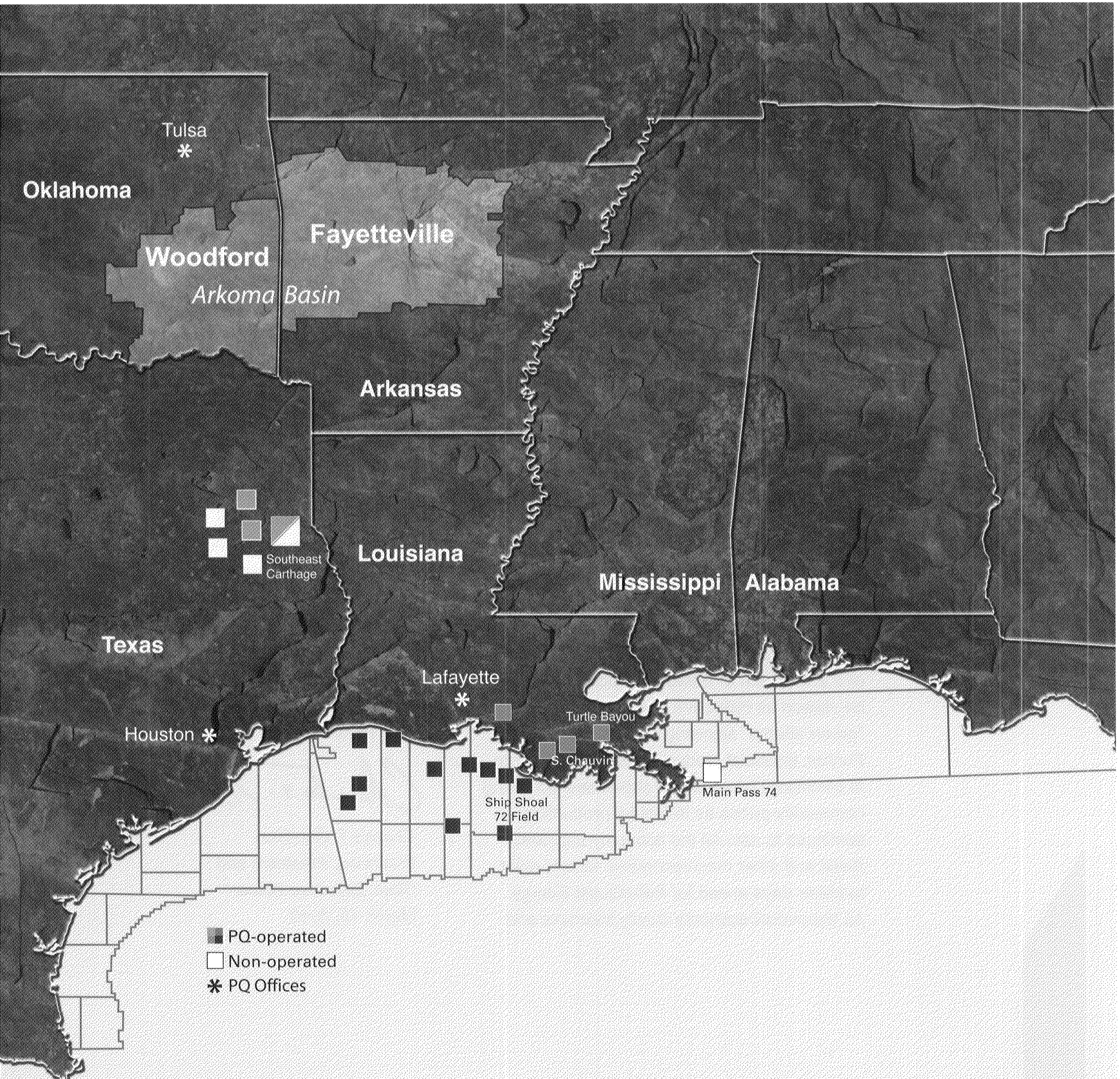
I remain convinced that the volatility we have experienced over the past two years represents an opportunity for PetroQuest to continue our transformation and ultimately return to growth. What this means in practice is that we will remain flexible to adjust our capital expenditure program to economically drill wells or to take other measures such as further reduction of debt as market conditions warrant. Our world-class asset base gives us this flexibility, and we need not undertake drilling activity for any other reason than to increase production and reserves economically. Our operations teams have made great strides to reduce drilling costs beyond the obvious savings associated with lower service costs, but inevitably service costs will rise again. The gains in drilling efficiencies we made in 2009 are permanent, and we will strive to continue lowering average drilling costs at the operational level. Looking ahead, we plan to drill 80-110 gross wells based on planned capital expenditures of $120-$140 million in 2010, an increase of 124% over 2009; 74% of our capital budget for next year is allocated to our long-lived assets. The bottom line is that PetroQuest is getting back to work in 2010 to continue growing the Company.

The Future of Energy in the United States

The domestic natural gas industry continues to ramp up its activity in terms of accurately portraying to our national political leaders and the general public that natural gas must be part of a comprehensive energy policy designed to reduce our dependence on foreign oil. I think it is fair to say our industry could have been engaged in dialogue with Washington earlier, but clearly the enormous natural gas resource base in the U.S. must be part of the country's energy policy as we seek ways to reduce oil imports, increase natural gas' contribution as a fuel for the fleet transportation sector, and evaluate the various renewable energy sources available in the near term of 5-15 years. I have personally participated in briefings to various levels of political leadership at the federal and state level, and my sense is that the natural gas industry is making great strides to ensure domestic producers are considered to be strategic resources for the future energy needs of our country. It is interesting to note that PetroQuest was not unique in 2009 in terms of deferring production and new projects. Indeed many independent producers curtailed activity as natural gas prices declined to $1.88 per MMbtu (NYMEX) on September 4, 2009. It is perhaps more interesting to note, however, that the overall reduction in drilling within the industry actually produced higher total production in 2009, which would seem to defy logic. How can our industry drill less and produce more, particularly when we were collectively worried a few years ago about lower production and competition from imported liquefied natural gas, or LNG? The answer lies in larger wells with more fracture stimulation stages in highly prolific resource basins undiscovered or under-exploited only three or four years ago. PetroQuest, along with other independent producers, have essentially demonstrated the viability of these new plays, such as the Woodford and Fayetteville Shales, and the abundant resource potential of domestically produced natural gas. Political leaders are listening, and PetroQuest will remain engaged to ensure we participate in the industry efforts to highlight our sector's role in contributing stable, secure production of natural gas as a critical component to reducing our dependence on foreign sources of energy.

2010 – Pillars of Strength and Stability Enable a Return to Growth

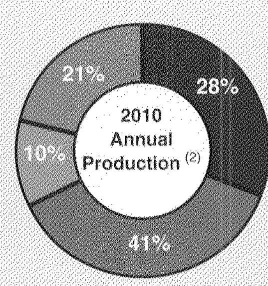
Last year I wrote about the four hallmarks of PetroQuest's growth story, including drilling within cash flow, conservative leverage ratios, high cash margins from our Gulf Coast property set, and the ability to control our own destiny as the operator of the majority of our projects. These are PetroQuest's "Four Pillars of Strength and Flexibility" which served us well in 2009 in allowing us to strengthen the balance sheet and ultimately positioned us to increase our drilling activity in 2010 substantially over 2009 levels.

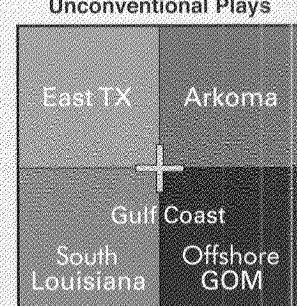


Reserve & Production Mix

	Proved Reserves [1]	Net Unrisked Inventory [1]
East Texas	30	182
Arkoma	109	1,401
South Louisiana	16	43
Offshore Gulf of Mexico	24	143
Total	**179**	**1,769**

[1] Reserves are as of December 31, 2009 (reserves are net and in Bcfe)
[2] Based on guidance for 2010 (84 MMcfe/day – 92 MMcfe/day)





Summary

As difficult as 2009 was for our industry, there are positive signs of an economy slowly beginning to emerge from a period of contraction, which analysts indicate began in December 2007. Although we may not return to the 4-5% growth rates in our national economy for some time, I am optimistic we will see increasing economic activity, industrial production, and greater emphasis on natural gas as a component of our country's drive for energy independence. Industrial production, which comprises approximately 41% of gross domestic product, increased in Q3 and Q4 2009, mirroring annualized GDP growth of 2.2%. Each of these data points can be viewed as indicative of the proverbial "green shoots" signaling a wider recovery. Further, industrial production tends to correlate to commodity prices, so we should see increasing commodity prices as industrial production continues to rise. As the economy improves, these and other macroeconomic factors point to better days ahead for PetroQuest Energy. As the overall economy slowly improves and natural gas prices modestly rise, PetroQuest is poised to increase our capital expenditures and operational activity through 2010. Our effort to address liquidity in 2009 was a great success; we have strengthened our balance sheet, and during 2010 we are prepared to resume the positive trajectory of production and reserve growth for which the Company is best known. Above all, I am mindful that we have both world class assets and one of the best teams in the business. We are all focused on resuming PetroQuest's growth trajectory, and all of the possibilities before us make this one of the most exciting times I have experienced in my career.

Best regards,

Charles T. Goodson

Charles T. Goodson
Chairman, President and
Chief Executive Officer
March 15, 2010

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark ne)

[X] Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2009
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: 001-32681

PETROQUEST ENERGY, INC.
(Exact name of registrant as specified in its charter)

State of incorporation: Delaware I.R.S. Employer Identification No. 72-1440714

400 E. Kaliste Saloom Road, Suite 6000 Lafayette, Louisiana 70508
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: (337) 232-7028

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $.001 per share	New York Stock Exchange
Preferred Stock Purchase Rights	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
[ ] Yes [X] 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 [X] 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.
[X] 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 definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):
[ ] Large accelerated filer [X] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).
[ ] Yes [X] No

The aggregate market value of the voting common equity held by non-affiliates of the registrant was approximately $181,470,000 as of June 30, 2009 (for purposes of this disclosure, the registrant assumed its directors, executive officers and beneficial owners of 5% or more of the registrant's common stock were affiliates).

As of February 23, 2010, the registrant had outstanding 63,155,200 shares of Common Stock, par value $.001 per share.

Document incorporated by reference: Proxy Statement of PetroQuest Energy, Inc. relating to the Annual Meeting of Stockholders to be held on May 12, 2010, which is incorporated by reference into Part III of this Form 10-K.

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This Form 10-K contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements other than statements of historical facts included in and incorporated by reference into this Form 10-K are forward looking statements. These forward-looking statements are subject to certain risks, trends and uncertainties that could cause actual results to differ materially from those projected.

Among those risks, trends and uncertainties are:

- the volatility of oil and natural gas prices and significantly depressed natural gas prices since the middle of 2008;
- our substantial amount of indebetedness and the significant amount of cash required to service our indebtedness;
- the recent financial crisis and continuing uncertain economic conditions in the United States and globally;
- ceiling test write-downs resulting, and that could result in the future, from lower oil and natural gas prices;
- our ability to obtain adequate financing to execute our long-term strategy when the need arises and to fund our planned capital expenditures;
- limits on our growth and our ability to finance our operations, fund our capital needs and respond to changing conditions imposed by restrictive debt covenants;
- our ability to find, develop, produce and acquire additional oil and natural gas reserves that are economically recoverable;
- approximately half of our production being exposed to the additional risk of severe weather, including hurricanes and tropical storms, as well as flooding, coastal erosion and sea level rise;
- losses and liabilities from uninsured or underinsured drilling and operating activities;
- our ability to market our oil and natural gas production;
- competition from larger oil and natural gas companies;
- the effect of new SEC rules on our estimates of proved reserves;
- the likelihood that our actual production, revenues and expenditures related to our reserves will differ from our estimates of proved reserves;
- our ability to identify, execute or efficiently integrate future acquisitions;
- losses or limits on potential gains resulting from hedging production;
- the loss of key management or technical personnel;
- the operating hazards attendant to the oil and gas business;
- governmental regulation relating to hydraulic fracturing and environmental compliance costs and environmental liabilities;
- the operation and profitability of non-operated properties; and
- potential conflicts of interest resulting from ownership of working interests and overriding royalty interests in certain of our properties by our officers and directors.

Although we believe that the expectations reflected in these forward looking statements are reasonable, we cannot assure you that such expectations reflected in these forward looking statements will prove to have been correct.

When used in this Form 10-K, the words "expect," "anticipate," "intend," "plan," "believe," "seek," "estimate" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain these identifying words. Because these forward-looking statements involve risks and uncertainties, actual results could differ materially from those expressed or implied by these forward-looking statements for a number of important reasons, including those discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations," "Risk Factors" and elsewhere in this Form 10-K.

You should read these statements carefully because they discuss our expectations about our future performance, contain projections of our future operating results or our future financial condition, or state other "forward-looking" information. You should be aware that the occurrence of any of the events described under "Management's Discussion and Analysis of Financial Condition and Results of Operations," "Risk Factors" and elsewhere in this Form 10-K could substantially harm our business, results of operations and financial condition and that upon the occurrence of any of these events, the trading price of our common stock could decline, and you could lose all or part of your investment.

We cannot guarantee any future results, levels of activity, performance or achievements. Except as required by law, we undertake no obligation to update any of the forward-looking statements in this Form 10-K after the date of this Form 10-K.

As used in this Form 10-K, the words "we," "our," "us," "PetroQuest" and the "Company" refer to PetroQuest Energy, Inc., its predecessors and subsidiaries, except as otherwise specified. We have provided definitions for some of the oil and natural gas industry terms used in this Form 10-K in "Glossary of Certain Oil and Natural Gas Terms" beginning on page 47.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

Overview

PetroQuest Energy, Inc. is an independent oil and gas company incorporated in the State of Delaware with operations in Oklahoma, Arkansas and Texas and the Gulf Coast Basin. We seek to grow our production, proved reserves, cash flow and earnings at low finding and development costs through a balanced mix of exploration, development and acquisition activities. From the commencement of our operations in 1985 through 2002, we were focused exclusively in the Gulf Coast Basin with onshore properties principally in southern Louisiana and offshore properties in the shallow waters of the Gulf of Mexico shelf. During 2003, we began the implementation of our strategic goal of diversifying our reserves and production into longer life and lower risk onshore properties. As part of the strategic shift to diversify our asset portfolio and lower our geographic and geologic risk profile, we refocused our opportunity selection processes to reduce our average working interest in higher risk projects, shift capital to higher probability of success onshore wells and mitigate the risks associated with individual wells by expanding our drilling program across multiple basins.

Utilizing the cash flow generated by our higher margin Gulf Coast Basin assets, we have successfully diversified into longer life basins in Oklahoma, Arkansas and Texas through a combination of selective acquisitions and drilling activity. Beginning in 2003 with our acquisition of the Carthage Field in Texas through 2009, we have invested approximately $650 million into growing our longer life assets. During the six year period ended December 31, 2009, we have realized a 97% drilling success rate on 551 gross wells drilled. Comparing 2009 metrics with those in 2003, the year we implemented our diversification strategy, we have grown production by 254% and estimated proved reserves by 115%. At December 31, 2009, 77% of our estimated proved reserves and 53% of our 2009 production were derived from our longer life assets.

In response to declining commodity prices and the uncertain outlook on the financial markets as a result of the global financial crisis, during late 2008 we made the decision to shift our focus for 2009 from increasing production and reserves to building liquidity and strengthening our balance sheet. As a result, we reduced our capital expenditures, including capitalized interest and overhead, by 83% in 2009 from $357.8 million in 2008 to $59.1 million in 2009. In addition to reducing our capital expenditures, we also reduced our operating expenses and general and administrative costs, excluding non-cash stock compensation expense, by a combined 21% during 2009 as compared to 2008. Finally, in June 2009 we completed a public offering of 11.5 million shares of our common stock receiving net proceeds of approximately $38 million. As a result of our liquidity building efforts in 2009, we repaid $101 million of bank debt. Despite our capital expenditure decreases, we were still able to increase production by 1% and only experienced a 3% decline in our estimated proved reserves, as compared to 2008.

Business Strategy

Maintain Our inancial lexibility. Having achieved our 2009 goal of strengthening our balance sheet, we plan to resume our strategy of growing reserves and production based on our outlook for commodity prices. Our 2010 capital expenditures, which include capitalized interest and overhead, are expected to range between $120 million and $140 million, a significant increase when compared to our actual 2009 capital expenditures of approximately $59.1 million. In order to maintain our financial flexibility, we plan to fund our 2010 capital expenditures budget with cash flow from operations. Because we operate approximately 75% of our total estimated proved reserves and manage the drilling and completion activities on an additional 15% of such reserves, we expect to be able to control the timing of a substantial portion of our capital investments. As a result, we expect to be able to actively manage our 2010 capital budget to stay within our projected cash flow from operations in the event commodity prices or the health of the global financial markets do not match our expectations. In addition to funding capital expenditures with cash flow from operations, during 2010 we plan to also maintain an active commodity hedging program and, as we did during prior years, we may opportunistically dispose of non-core or mature assets to reduce debt or to provide capital for higher potential exploration and development properties that fit our long-term growth strategy.

Concentrate in Core Operating Areas and Build Scale. We plan to continue focusing our operations in Oklahoma, Arkansas, Texas and the Gulf Coast Basin. Operating in concentrated areas helps us better control our overhead by enabling us to manage a greater amount of acreage with fewer employees and minimize incremental costs of increased drilling and production. We have substantial geological and reservoir data, operating experience and partner relationships in these regions. We believe that these factors, coupled with the existing infrastructure and favorable geologic conditions with multiple known oil and gas producing reservoirs in these regions, will provide us with attractive investment opportunities.

Pursue Balanced Growth and Portfolio Mix. We plan to pursue a risk-balanced approach to the growth and stability of our reserves, production, cash flows and earnings. Our goal is to strike a balance between lower risk development activities and higher risk and higher impact exploration activities. We plan to allocate our 2010 capital investments in a manner that continues to geographically and operationally diversify our asset base. Through our portfolio diversification efforts, at December 31, 2009, approximately 77% of our estimated proved reserves were located in longer life and lower risk basins in Oklahoma, Arkansas and Texas and 23% were located in the shorter life, but higher flow rate reservoirs in the Gulf Coast Basin. This compares to 68% and 61% of our estimated proved reserves located in longer life basins at December 31, 2008 and 2007, respectively. In terms of production diversification, during 2009, 53% of our production was derived from longer life basins versus 47% and 27% in 2008 and 2007, respectively.

Manage Our Risk Exposure. We plan to continue several strategies designed to mitigate our operating risks. Since 2003, we have adjusted the working interest we are willing to hold based on the risk level and cost exposure of each project. For example, we typically reduce our working interests in higher risk exploration projects while retaining greater working interests in lower risk development projects. Our partners often agree to pay a disproportionate share of drilling costs relative to their interests, allowing us to allocate our capital spending to maximize our return and reduce the inherent risk in exploration and development activities. We also strive to retain operating control of the majority of our properties to control costs and timing of expenditures and we expect to continue to actively hedge a portion of our future planned production to mitigate the impact of commodity price fluctuations and achieve more predictable cash flows.

Target Underexploited Properties with Substantial Opportunity for Upside. We plan to maintain a rigorous prospect selection process that enables us to leverage our operating and technical experience in our core operating areas. We intend to primarily target properties that provide us with exposure to longer life reserves and production. In evaluating these targets, we seek properties that provide sufficient acreage for future exploration and development, as well as properties that may benefit from the latest exploration, drilling, completion and operating techniques to more economically find, produce and develop oil and gas reserves.

2009 Financial and Operational Summary

During 2009, we invested $59.1 million in exploratory, development and acquisition activities as we drilled 66 gross exploratory wells and 16 gross development wells realizing an overall success rate of 98%. These activities were financed through our cash flow from operating activities. Despite the significant decline in capital investment during 2009, our production increased 1% to a Company annual record of 34.2 Bcfe. In 2009, we issued 11.5 million shares of our common stock receiving net proceeds of approximately $38 million. Using these proceeds and cash flow from our operating activities, we reduced our outstanding borrowings under our bank credit facility from $130 million at the end of 2008 to $29 million at the end of 2009, reducing our total outstanding debt by 36% when compared to the end of 2008.

Oil and Gas Reserves

In 2009, the SEC issued a revision to Staff Accounting Bulletin 113 ("SAB 113") which changed the guidelines for estimating proved reserves. The principal revisions include: the price used in determining quantities of oil and gas reserves; elimination of post-quarter-end prices to evaluate limitations of capitalized costs under the full cost method of accounting; a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking; and removal of the exclusion of unconventional oil and gas extraction methods as oil and gas producing activities. Our reserves were primarily affected by the change in pricing methodology, which is now calculated by the unweighted arithmetic average of the first-day-of-the-month market price for oil and gas during the 12-month period prior to the ending date of the balance sheet. The previous SEC methodology required reserves to be priced using the closing price as of the last business day of the reporting period. Use of the year-end pricing methodology at December 31, 2009 would have resulted in an increase in proved reserves of approximately 36 Bcfe. A summary of the impact of the change in reserve estimation methodology on our reserves is as follows:

	New SEC Methodology	Previous SEC Methodology
Oil price (per Bbl) pre differentials	$ 61.18	$ 79.36
Oil price (per Bbl) with differentials	$ 60.57	$ 78.75
Gas price (per Mcfe) pre differentials	$ 3.87	$ 5.79
Gas price (per Mcfe) with differentials	$ 2.97	$ 5.01
Total Proved Reserves (Bcfe)	178.9	202.2
Standardized Measure (M$)	$ 174,288	$ 344,466

Our estimated proved reserves under the revised SEC guidelines at December 31, 2009 decreased 3% from 2008 totaling 1,931 MBbls of oil and 167,361 MMcfe of natural gas, with a pre-tax present value, discounted at 10%, of the estimated future net revenues based on average prices during 2009 ("PV-10") of $177.0 million. At December 31, 2009, our standardized measure of discounted cash flows, which includes the estimated impact of future income taxes, totaled $174.3 million. Our standardized measure of discounted cash flows at December 31, 2009 was 45% below 2008 as we utilized the revised SEC pricing methodology of $60.57 per barrel and $2.97 per Mcfe (adjusted for field differentials) in 2009, compared to year-end pricing of $41.53 per barrel and $4.64 per Mcfe at December 31, 2008. See the reconciliation of PV-10 to the standardized measure of discounted cash flows below.

The decline in gas prices and the corresponding revised pricing methodology described in more detail above had a negative impact on certain of our estimated proved reserves and related estimated net cash flows. As a result, we recorded $156.1 million in ceiling test write-downs during 2009. Under the previous SEC reserve reporting methodology, we would not have recorded a ceiling test write-down in the fourth quarter of $52.6 million and our estimated proved reserves at December 31, 2009 would have been 202 Bcfe, a 9% increase as compared to 2008.

Ryder Scott Company, L.P. and Netherland, Sewell and Associates, Inc., each of which are nationally recognized independent petroleum engineering firms, prepared the estimates of our proved reserves and future net cash flows (and present value thereof) attributable to such proved reserves at December 31, 2009. Ryder Scott Company, L.P. prepared the estimates related to our Gulf Coast Basin, including offshore Louisiana, and East Texas properties and Netherland, Sewell and Associates, Inc. prepared the estimates of our Arkansas and Oklahoma properties. The estimates prepared by Ryder Scott Company, L.P. accounted for approximately 40% of the total proved reserves (on a Bcfe basis) at December 31, 2009 and 75% of the total estimated discounted pre-tax future net cash flows. The estimates prepared by Netherland, Sewell and Associates, Inc. accounted for the remaining 60% of our total proved reserves (on a Bcfe basis) at December 31, 2009 and 25% of the estimated discounted pre-tax future net cash flows.

The following table sets forth certain information about our estimated proved reserves as of December 31, 2009.

	Oil (MBbls)	Natural Gas and NGL (Mmcfe)	Total Mmcfe
Proved Developed	1,775	100,430	111,080
Proved Undeveloped	156	66,931	67,867
Total Proved	1,931	167,361	178,947

As of December 31, 2009, our proved undeveloped reserves ("PUDs") totaled 67.9 Bcfe, a 38% increase from our PUD balance at December 31, 2008. During 2009, we spent $4.3 million converting 3.7 Bcfe of PUDs at December 31, 2008 to proved developed at December 31, 2009. The majority of the increase in our PUDs during 2009 was the result of positive performance revisions and additions of PUDs from extensions and discoveries related to our Oklahoma assets. Offsetting these increases was a reduction to PUDs totaling approximately 26 Bcfe as a result of lower pricing.

Approximately 73% of our total PUDs at December 31, 2009 were associated with the future development of our Oklahoma properties. We expect all of our PUDs at December 31, 2009 to be developed over the next five years. At December 31, 2009, we had one PUD totaling less than 0.4 Bcfe that had been booked for longer than five years. We are currently evaluating the near-term development of this PUD. Estimated future costs related to the development of PUDs are expected to total $20.5 million in 2010, $36.1 million in 2011 and $49.7 million in 2012.

The estimated cash flows from our proved reserves at December 31, 2009 were as follows:

	Proved Developed (M$)	Proved Undeveloped (M$)	Total Proved (M$)
Estimated pre-tax future net cash flows (1)	$233,201	$39,070	$272,271
Discounted pre-tax future net cash flows (PV-10) (1)	$179,520	($2,525)	$176,995
Total standardized measure of discounted future net cash flows	-	-	$174,288

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(1) Estimated pre-tax future net cash flows and discounted pre-tax future net cash flows (PV-10) are non-GAAP measures because they exclude income tax effects. Management believes these non-GAAP Measures are useful to investors as they are based on prices, costs and discount factors which are consistent from company to company, while the standardized measure of discounted future net cash flows is dependent on the unique tax situation of each individual company. As a result, the Company believes that investors can use these non-GAAP measures as a basis for comparison of the relative size and value of the Company's reserves to other companies. The Company also understands that securities analysts and rating agencies use these non-GAAP measures in similar ways. The following table reconciles undiscounted and discounted future net cash flows to standardized measure of discounted cash flows as of December 31, 2009:

	Total Proved (M$)
Estimated pre-tax future net cash flows	$272,271
10% annual discount	(95,276)
Discounted pre-tax future net cash flows	176,995
Future income taxes discounted at 10%	(2,707)
Standardized measure of discounted future net cash flows	$174,288

We have not filed any reports with other federal agencies that contain an estimate of total proved net oil and gas reserves.

Core Areas

Oklahoma

During late 2006, we began our initial drilling program to evaluate the Woodford Shale formation on a substantial portion of our Oklahoma acreage. During 2009, we continued our evaluation of the Woodford Shale as we drilled and participated in 15 gross wells, achieving a 100% success rate. In total, we invested $19 million in Oklahoma during 2009 in acquiring prospective Woodford Shale acreage and drilling and completing wells. As a result of our success in targeting the Woodford Shale, average daily production from our Oklahoma properties during 2009 increased to 29 MMcfe per day, a 15% increase from our 2008 average daily production. In addition to growing production, we experienced positive performance revisions to our proved reserves, which when combined with reserves added from our 2009 drilling program, resulted in a 43% increase in our estimated proved reserves from our Oklahoma properties. We have allocated approximately 62% of our 2010 capital budget to operations in Oklahoma.

Arkansas

During 2007, we closed several transactions acquiring a leasehold position in Arkansas. During late 2007, we began participating in an aggressive drilling program on this acreage targeting the Fayetteville Shale. This drilling program continued during 2009 as we participated in 65 gross wells, all of which were successful. In total we invested $15 million in Arkansas during 2009. As a result of our wells drilled in 2008 and our 2009 investments, we grew production to an average of 8 MMcfe per day in 2009, an 80% increase from our 2008 average daily production. However, our estimated proved reserves in this region declined 35% primarily due to the revised SEC reserve pricing methodology and curtailed drilling operations. We have allocated approximately 6% of our 2010 capital budget to participating in third-party operated Fayetteville Shale wells.

Texas

During 2009, we invested $3 million on completions and maintenance of our Texas properties. As part of our goal of building liquidity, we deferred significant development in this area during 2009. Net production from our Texas assets averaged 12 MMcfe per day during 2009, a 17% decrease from 2008 average daily production. Our estimated proved reserves in this area declined 29% primarily due to the revised SEC reserve pricing methodology. We have allocated approximately 6% of our 2010 capital budget to drilling and completing wells in this area.

Gulf Coast Basin

During 2009, we invested $16.7 million in this area primarily on facilities and completions. We also drilled one well and participated in one well onshore in south Louisiana, neither of which was commercially productive. Production from this area decreased 8% from 2008 totaling 44.8 MMcfe per day in 2009. Our estimated proved reserves in this area declined 31% from 2008 primarily as a result of reduced capital investments during 2009. We have allocated approximately 25% of our 2010 capital budget to various drilling and maintenance projects in this area.

Markets and Customers

We sell our oil and natural gas production under fixed or floating market contracts. Customers purchase all of our oil and natural gas production at current market prices. The terms of the arrangements generally require customers to pay us within 30 days after the production month ends. As a result, if the customers were to default on their payment obligations to us, near-term earnings and cash flows would be adversely affected. However, due to the availability of other markets and pipeline connections, we do not believe that the loss of these customers or any other single customer would adversely affect our ability to market production. Our ability to market oil and natural gas from our wells depends upon numerous factors beyond our control, including:

- the extent of domestic production and imports of oil and natural gas;
- the proximity of the natural gas production to pipelines;
- the availability of capacity in such pipelines;
- the demand for oil and natural gas by utilities and other end users;
- the availability of alternative fuel sources;
- the effects of inclement weather;

- state and federal regulation of oil and natural gas production; and
- federal regulation of gas sold or transported in interstate commerce.

We cannot assure you that we will be able to market all of the oil or natural gas we produce or that favorable prices can be obtained for the oil and natural gas we produce.

A portion of the production that we operate in Oklahoma is committed to a firm transportation agreement. Under the terms of the agreement we must deliver 9.1 Bcf of natural gas per year through October 31, 2013.

In view of the many uncertainties affecting the supply and demand for oil, natural gas and refined petroleum products, we are unable to predict future oil and natural gas prices and demand or the overall effect such prices and demand will have on the Company. During 2009, two customers individually accounted for 17% each, one accounted for 13% and one accounted for 12% of our oil and natural gas revenue. During 2008, one customer accounted for 23%, three accounted for 11% each and one accounted for 10% of our oil and natural gas revenue. During 2007, we had three customers who individually accounted for 32%, 16% and 12% of our oil and natural gas revenue. These percentages do not consider the effects of commodity hedges. We do not believe that the loss of any of our oil or natural gas purchasers would have a material adverse effect on our operations due to the availability of other purchasers.

Production, Pricing and Production Cost Data

The following table sets forth our production, pricing and production cost data during the periods indicated:

	Year Ended December 31,		
	2009	2008	2007
Production:			
Oil (Bbls)	600,124	680,571	1,079,672
Gas (Mcfe)	30,598,092	29,708,204	24,965,789
Total Production (Mcfe)	34,198,836	33,791,630	31,443,821
Average sales prices (1):			
Oil (per Bbl)	$ 59.31	$ 100.61	$ 71.25
Gas (per Mcfe)	3.37	8.36	6.78
Per Mcfe	4.06	9.38	7.83
Average Production Cost per Mcfe (2)	$ 1.13	$ 1.32	$ 1.02

(1) Does not include the effect of hedges

(2) Production costs do not include production taxes

Oil and Gas Drilling Activity

The following table sets forth the wells drilled and completed by us during the periods indicated. All wells were drilled in the continental United States:

	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Exploration:						
Productive	64	5.84	103	27.64	54	26.12
Non-productive	2	0.48	6	1.63	9	2.86
Total	66	6.32	109	29.27	63	28.98
Development:						
Productive	16	1.70	41	10.77	22	7.89
Non-productive	-	-	-	-	2	0.15
Total	16	1.70	41	10.77	24	8.04

We owned working interests in 15 gross (9 net) producing oil wells and 871 gross (277 net) producing gas wells at December 31, 2009. Of the 886 gross productive wells at December 31, 2009, 13 had dual completions. At December 31, 2009, we had 40 gross (3 net) wells in progress.

Leasehold Acreage

The following table shows our approximate developed and undeveloped (gross and net) leasehold acreage as of December 31, 2009:

	Leasehold Acreage			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Alabama	135	46	3,432	2,200
Arkansas	17,785	5,035	37,416	11,802
Louisiana	7,304	2,301	8,955	3,350
Mississippi	1,628	1,178	-	-
Oklahoma	73,387	36,427	27,775	25,826
Texas	45,366	24,660	21,515	18,430
Federal Waters	66,731	28,308	16,416	11,704
Total	212,336	97,955	115,509	73,312

Leases covering 32% of our net undeveloped acreage are scheduled to expire in 2010, 45% in 2011, 8% in 2012 and 15% thereafter.

Title to Properties

We believe that the title to our oil and gas properties is good and defensible in accordance with standards generally accepted in the oil and gas industry, subject to such exceptions which, in our opinion, are not so material as to detract substantially from the use or value of such properties. Our properties are typically subject, in one degree or another, to one or more of the following:

- royalties and other burdens and obligations, express or implied, under oil and gas leases;
- overriding royalties and other burdens created by us or our predecessors in title;
- a variety of contractual obligations (including, in some cases, development obligations) arising under operating agreements, farmout agreements, production sales contracts and other agreements that may affect the properties or their titles;

- back-ins and reversionary interests existing under purchase agreements and leasehold assignments;
- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing obligations to unpaid suppliers and contractors and contractual liens under operating agreements; pooling, unitization and communitization agreements, declarations and orders; and
- easements, restrictions, rights-of-way and other matters that commonly affect property.

To the extent that such burdens and obligations affect our rights to production revenues, they have been taken into account in calculating our net revenue interests and in estimating the size and value of our reserves. We believe that the burdens and obligations affecting our properties are conventional in the industry for properties of the kind that we own.

Federal Regulations

Sales and Transportation of Natural Gas. Historically, the transportation and sales for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938 ("NGA"), the Natural Gas Policy Act of 1978 ("NGPA") and Federal Energy Regulatory Commission ("FERC") regulations. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act deregulated the price for all "first sales" of natural gas. Thus, all of our sales of gas may be made at market prices, subject to applicable contract provisions. Sales of natural gas are affected by the availability, terms and cost of pipeline transportation. Since 1985, the FERC has implemented regulations intended to make natural gas transportation more accessible to gas buyers and sellers on an open-access, non-discriminatory basis. We cannot predict what further action the FERC will take on these matters. Some of the FERC's more recent proposals may, however, adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any action taken materially differently than other natural gas producers, gatherers and marketers with which we compete.

The Outer Continental Shelf Lands Act (the "OCSLA") requires that all pipelines operating on or across the shelf provide open-access, non-discriminatory service. There are currently no regulations implemented by the FERC under its OCSLA authority on gatherers and other entities outside the reach of its NGA jurisdiction. Therefore, we do not believe that any FERC or Minerals Management Service (the "MMS") action taken under OCSLA will affect us in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers with which we compete.

Our natural gas sales are generally made at the prevailing market price at the time of sale. Therefore, even though we sell significant volumes to major purchasers, we believe that other purchasers would be willing to buy our natural gas at comparable market prices.

Natural gas continues to supply a significant portion of North America's energy needs and we believe the importance of natural gas in meeting this energy need will continue. The impact of the ongoing economic downturn on natural gas supply and demand fundamentals has resulted in extremely volatile natural gas prices, which is expected to continue.

On August 8, 2005, the Energy Policy Act of 2005 (the "2005 EPA") was signed into law. This comprehensive act contains many provisions that will encourage oil and gas exploration and development in the U.S. The 2005 EPA directs the FERC, MMS and other federal agencies to issue regulations that will further the goals set out in the 2005 EPA. The 2005 EPA amends the NGA to make it unlawful for "any entity", including otherwise non-jurisdictional producers such as us, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. On January 20, 2006, the FERC issued rules implementing this provision. The rules make it unlawful in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction. It therefore reflects a significant expansion of the FERC's enforcement authority. We do not anticipate we will be affected any differently than other producers of natural gas.

Sales and Transportation of Crude Oil. Our sales of crude oil, condensate and natural gas liquids are not currently regulated, and are subject to applicable contract provisions made at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to the FERC's jurisdiction under the Interstate Commerce Act. In other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes.

The regulation of pipelines that transport crude oil, condensate and natural gas liquids is generally more light-handed than the FERC's regulation of gas pipelines under the NGA. Regulated pipelines that transport crude oil, condensate, and natural gas liquids are subject to common carrier obligations that generally ensure non-discriminatory access. With respect to interstate pipeline transportation subject to regulation of the FERC under the Interstate Commerce Act, rates generally must be cost-based, although market-based rates or negotiated settlement rates are permitted in certain circumstances. Pursuant to FERC Order No. 561, pipeline rates are subject to an indexing methodology. Under this indexing methodology, pipeline rates are subject to changes in the Producer Price Index for Finished Goods, minus one percent. A pipeline can seek to increase its rates above index levels provided that the pipeline can establish that there is a substantial divergence between the actual costs experienced by the pipeline and the rate resulting from application of the index. A pipeline can seek to charge market based rates if it establishes that it lacks significant market power. In addition, a pipeline can establish rates pursuant to settlement if agreed upon by all current shippers. A pipeline can seek to establish initial rates for new services through a cost-of-service proceeding, a market-based rate proceeding, or through an agreement between the pipeline and at least one shipper not affiliated with the pipeline.

Federal Leases. We maintain operations located on federal oil and gas leases, which are administered by the MMS pursuant to the OCSLA. These leases are issued through competitive bidding and contain relatively standardized terms. These leases require compliance with detailed MMS regulations and orders that are subject to interpretation and change by the MMS.

For offshore operations, lessees must obtain MMS approval for exploration, development and production plans prior to the commencement of such operations. In addition to permits required from other agencies such as the Coast Guard, the Army Corps of Engineers and the United States Environmental Protection Agency ("USEPA"), lessees must obtain a permit from the MMS prior to the commencement of drilling. The MMS has promulgated regulations requiring offshore production facilities located on the Outer Continental Shelf to meet stringent engineering and construction specifications. The MMS also has regulations restricting the flaring or venting of natural gas, and prohibiting the flaring of liquid hydrocarbons and oil without prior authorization. Similarly, the MMS has promulgated other regulations governing the plugging and abandonment of wells located offshore and the installation and removal of all production facilities.

To cover the various obligations of lessees on the Outer Continental Shelf, the MMS generally requires that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be met. The cost of these bonds or assurances can be substantial, and there is no assurance that they can be obtained in all cases. We are currently exempt from the supplemental bonding requirements of the MMS. Under some circumstances, the MMS may require operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition, cash flows and results of operations.

The MMS also administers the collection of royalties under the terms of the OCSLA and the oil and gas leases issued under the Act. The amount of royalties due is based upon the terms of the oil and gas leases as well as of the regulations promulgated by the MMS. The MMS regulations governing the calculation of royalties and the valuation of crude oil produced from federal leases provide that the MMS will collect royalties based upon the market value of oil produced from federal leases. The 2005 EPA formalizes the royalty in-kind program of the MMS, providing that the MMS may take royalties in-kind if the Secretary of the Interior determines that the benefits are greater than or equal to the benefits that are likely to have been received had royalties been taken in value. These regulations are amended from time to time, and the amendments can affect the amount of royalties that we are obligated to pay to the MMS. However, we do not believe that these regulations or any future amendments will affect us in a way that materially differs from the way it affects other oil and gas producers, gatherers and marketers.

Federal, State or American Indian Leases. In the event we conduct operations on federal, state or American Indian oil and gas leases, such operations must comply with numerous regulatory restrictions, including various nondiscrimination statutes, and certain of such operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the Bureau of Land Management ("BLM") or MMS or other appropriate federal or state agencies.

The Mineral Leasing Act of 1920 ("Mineral Act") prohibits direct or indirect ownership of any interest in federal onshore oil and gas leases by a foreign citizen of a country that denies "similar or like privileges" to citizens of the United States. Such restrictions on citizens of a "non-reciprocal" country include ownership or holding or controlling stock in a corporation that holds a federal onshore oil and gas lease. If this restriction is violated, the corporation's lease can be cancelled in a proceeding instituted by the United States Attorney General. Although the regulations of the BLM (which administers the Mineral Act) provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. We own interests in numerous federal onshore oil and gas leases. It is possible that holders of our equity interests may be citizens of foreign countries, which at some time in the future might be determined to be non-reciprocal under the Mineral Act.

State Regulations

Most states regulate the production and sale of oil and natural gas, including:

- requirements for obtaining drilling permits;
- the method of developing new fields;
- the spacing and operation of wells;
- the prevention of waste of oil and gas resources; and
- the plugging and abandonment of wells.

The rate of production may be regulated and the maximum daily production allowable from both oil and gas wells may be established on a market demand or conservation basis or both.

We may enter into agreements relating to the construction or operation of a pipeline system for the transportation of natural gas. To the extent that such gas is produced, transported and consumed wholly within one state, such operations may, in certain instances, be subject to the jurisdiction of such state's administrative authority charged with the responsibility of regulating intrastate pipelines. In such event, the rates that we could charge for gas, the transportation of gas, and the construction and operation of such pipeline would be subject to the rules and regulations governing such matters, if any, of such administrative authority.

Legislative Proposals

In the past, Congress has been very active in the area of natural gas regulation. New legislative proposals in Congress and the various state legislatures, if enacted, could significantly affect the petroleum industry. At the present time it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on our operations.

Environmental Regulations

General. Our activities are subject to existing federal, state and local laws and regulations governing environmental quality and pollution control. Although no assurances can be made, we believe that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, regulations and rules regulating the release of materials in the environment or otherwise relating to the protection of human health, safety and the environment will not have a material effect upon our capital expenditures, earnings or competitive position with respect to our existing assets and operations. We cannot predict what effect additional regulation or legislation, enforcement policies thereunder, and claims for damages to property, employees, other persons and the environment resulting from our operations could have on our activities.

Our activities with respect to exploration and production of oil and natural gas, including the drilling of wells and the operation and construction of pipelines, plants and other facilities for extracting, transporting, processing, treating or storing natural gas and other petroleum products, are subject to stringent environmental regulation by state and federal authorities, including the USEPA. Such regulation can increase the cost of planning, designing, installation and operation of such facilities. Although we believe that compliance with environmental regulations will not have a material adverse effect on us, risks of substantial costs and liabilities are inherent in oil and gas production operations, and there can be no assurance that significant costs and liabilities will not be incurred. Moreover it is possible that other developments, such as spills or other unanticipated releases, stricter environmental laws and regulations, and claims for damages to property or persons resulting from oil and gas production, would result in substantial costs and liabilities to us.

Solid and Hazardous Waste. We own or lease numerous properties that have been used for production of oil and gas for many years. Although we have utilized operating and disposal practices standard in the industry at the time, hydrocarbons or other solid wastes may have been disposed or released on or under these properties. In addition, many of these properties have been operated by third parties. We had no control over such entities' treatment of hydrocarbons or other solid wastes and the manner in which such substances may have been disposed or released. State and federal laws applicable to oil and gas wastes and properties have gradually become stricter over time. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future contamination.

We generate wastes, including hazardous wastes, which are subject to regulation under the federal Resource Conservation and Recovery Act ("RCRA") and state statutes. The USEPA has limited the disposal options for certain hazardous wastes. Furthermore, it is possible that certain wastes generated by our oil and gas operations which are currently exempt from regulation as "hazardous wastes" may in the future be designated as "hazardous wastes" under RCRA or other applicable statutes, and therefore be subject to more rigorous and costly disposal requirements.

Superfund. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain persons with respect to the release or threatened release of a "hazardous substance" into the environment. These persons include the owner and operator of a site and persons that disposed or arranged for the disposal of hazardous substances at a site. CERCLA also authorizes the USEPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible persons the costs of such action. State statutes impose similar liability. Neither we nor our predecessors have been designated as a potentially responsible party by the USEPA or a state under CERCLA or a similar state law with respect to any such site.

Oil Pollution Act. The Oil Pollution Act of 1990 (the "OPA") and regulations thereunder impose a variety of regulations on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. A "responsible party" includes the owner or operator of a facility or vessel, or the lessee or permittee of the area in which an offshore facility is located. The OPA assigns liability to each responsible party for oil removal costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by the OPA.

The OPA establishes a liability limit for onshore facilities of $350 million and for offshore facilities of all removal costs plus $75 million, and lesser limits for some vessels depending upon their size. The regulations promulgated under OPA impose proof of financial responsibility requirements that can be satisfied through insurance, guarantee, indemnity, surety bond, letter of credit, qualification as a self-insurer, or a combination thereof. The amount of financial responsibility required depends upon a variety of factors including the type of facility or vessel, its size, storage capacity, oil throughput, proximity to sensitive areas, type of oil handled, history of discharges and other factors. We believe we currently have established adequate financial responsibility. While financial responsibility requirements under OPA may be amended to impose additional costs on us, the impact of any change in these requirements should not be any more burdensome to us than to others similarly situated.

Clean Water Act. The Clean Water Act ("CWA") regulates the discharge of pollutants to waters of the United States, including wetlands, and requires a permit for the discharge of pollutants, including petroleum, to such waters. Certain facilities that store or otherwise handle oil are required to prepare and implement Spill Prevention, Control and Countermeasure Plans and Facility Response Plans relating to the possible discharge of oil to surface waters. We are required to prepare and comply with such plans and to obtain and comply with discharge permits. We believe we are in substantial compliance with these requirements and that any noncompliance would not have a material adverse effect on us. The CWA also prohibits spills of oil and hazardous substances to waters of the United States in excess of levels set by regulations and imposes liability in the event of a spill. State laws further provide civil and criminal penalties and liabilities for spills to both surface and groundwaters and require permits that set limits on discharges to such waters.

Air Emissions. Our operations are subject to local, state and federal regulations for the control of emissions from sources of air pollution. Administrative enforcement actions for failure to comply strictly with air regulations or permits may be resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could impose civil and criminal liability for non-compliance. An agency could require us to forego construction or operation of certain air emission sources. We believe that we are in substantial compliance with air pollution control requirements and that, if a particular permit application were denied, we would have enough permitted or permittable capacity to continue our operations without a material adverse effect on any particular producing field.

According to certain scientific studies, emissions of carbon dioxide, methane, nitrous oxide and other gases commonly known as greenhouse gases ("GHG") may be contributing to global warming of the earth's atmosphere and to global climate change. In response to the scientific studies, legislative and regulatory initiatives are underway to limit GHG emissions. The U.S. Congress is considering legislation that would control GHG emissions through a "cap and trade" program and several states have already implemented programs to reduce GHG emissions. The U.S. Supreme Court determined that GHG emissions fall within the federal Clean Air Act ("CAA") definition of an "air pollutant", and in response the USEPA promulgated an endangerment finding paving the way for regulation of GHG emissions under the CAA. The USEPA has also promulgated rules requiring large sources to report their GHG emissions. Although these reporting regulations are not currently applicable to the Company, these reporting rules may be expanded in the future to apply to additional sources. In addition, the USEPA has proposed rules that would significantly increase the GHG emission threshold that would identify major stationary sources of GHG subject to CAA permitting programs. Because regulation of GHG emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. Such developments may affect how these GHG initiatives will impact the Company. However, apart from these developments, recent judicial decisions that have allowed certain tort claims alleging property damage to proceed against GHG emissions sources may increase the Company's litigation risk for such claims. Due to the uncertainties surrounding the regulation of and other risks associated with GHG emissions, the Company cannot predict the financial impact of related developments on the Company.

Coastal Coordination. There are various federal and state programs that regulate the 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 Nation's coastal zone. The CZMA provides for federal grants for state management programs that regulate land use, water use and coastal development.

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 oil and gas, and pipelines for the gathering, transportation or transmission of oil, 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.

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 ("CMP") 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.

OSHA. We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendments and Reauthorization Act and similar state statutes require us to organize and/or disclose information about hazardous materials used or produced in our operations. Certain of this information must be provided to employees, state and local governmental authorities and local citizens.

Management believes that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us.

Corporate Offices

Our headquarters are located in Lafayette, Louisiana, in approximately 46,000 square feet of leased space, with exploration offices in Houston, Texas and Tulsa, Oklahoma, in approximately 5,500 square feet and 10,000 square feet, respectively, of leased space. We also maintain owned or leased field offices in the areas of the major fields in which we operate properties or have a significant interest. Replacement of any of our leased offices would not result in material expenditures by us as alternative locations to our leased space are anticipated to be readily available.

Employees

We had 99 full-time employees as of February 1, 2010. In addition to our full time employees, we utilize the services of independent contractors to perform certain functions. We believe that our relationships with our employees are satisfactory. None of our employees are covered by a collective bargaining agreement.

Available Information

We make available free of charge, or through the "Investors - SEC Documents" section of our website at www.petroquest.com, access to our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after such material is filed, or furnished to the Securities and Exchange Commission. Our Code of Business Conduct and Ethics, our Corporate Governance Guidelines and the charters of our Audit, Compensation and Nominating and Corporate Governance Committees are also available through the "Investors - Corporate Governance" section of our website or in print to any stockholder who requests them.

ITEM 1A. RISK FACTORS

Risks Related to Our Business, Industry and Strategy

Oil and natural gas prices are volatile, and natural gas prices have been significantly depressed since the middle of 2008. An extended decline in the prices of oil and natural gas would likely have a material adverse effect on our financial condition, liquidity, ability to meet our financial obligations and results of operations.

Our future financial condition, revenues, results of operations, profitability and future growth, and the carrying value of our oil and natural gas properties depend primarily on the prices we receive for our oil and natural gas production. Our ability to maintain or increase our borrowing capacity and to obtain additional capital on attractive terms also substantially depends upon oil and natural gas prices. Prices for natural gas have been significantly depressed since the middle of 2008 and future oil and natural gas prices are subject to large fluctuations in response to a variety of factors beyond our control.

These factors include:

- relatively minor changes in the supply of or the demand for oil and natural gas;
- the condition of the United States and worldwide economies;
- market uncertainty;
- the level of consumer product demand;
- weather conditions in the United States, such as hurricanes;
- the actions of the Organization of Petroleum Exporting Countries;
- domestic and foreign governmental regulation and taxes, including price controls adopted by the Federal Energy Regulatory Commission;
- political conditions or hostilities in oil and natural gas producing regions, including the Middle East and South America;
- the price and level of foreign imports of oil and natural gas; and
- the price and availability of alternate fuel sources.

We cannot predict future oil and natural gas prices and such prices may decline further. An extended decline in oil and natural gas prices may adversely affect our financial condition, liquidity, ability to meet our financial obligations and results of operations. Lower prices have reduced and may further reduce the amount of oil and natural gas that we can produce economically and has required and may require us to record additional ceiling test write-downs. Substantially all of our oil and natural gas sales are made in the spot market or pursuant to contracts based on spot market prices. Our sales are not made pursuant to long-term fixed price contracts.

To attempt to reduce our price risk, we periodically enter into hedging transactions with respect to a portion of our expected future production. We cannot assure you that such transactions will reduce the risk or minimize the effect of any decline in oil or natural gas prices. Any substantial or extended decline in the prices of or demand for oil or natural gas would have a material adverse effect on our financial condition, liquidity, ability to meet our financial obligations and results of operations.

We have a substantial amount of indebtedness, which may adversely affect our cash flow and our ability to operate our business, remain in compliance with debt covenants and make payments on our debt.

As of December 31, 2009, the aggregate amount of our outstanding indebtedness, net of available cash on hand, was approximately $157.5 million, which could have important consequences for you, including the following:

- it may be more difficult for us to satisfy our obligations with respect to our 10 3/8% senior notes due 2012, which we refer to as our 10 3/8% notes, and any failure to comply with the obligations of any of our debt agreements, including financial and other restrictive covenants, could result in an event of default under the indenture governing our 10 3/8% notes and the agreements governing such other indebtedness;

- the covenants contained in our debt agreements limit our ability to borrow money in the future for acquisitions, capital expenditures or to meet our operating expenses or other general corporate obligations;

- we will need to use a substantial portion of our cash flows to pay principal and interest on our debt, approximately $15.6 million per year for interest on our 10 3/8% notes alone, and to pay quarterly dividends, if declared by our Board of Directors, on our Series B Preferred Stock, approximately $5.1 million per year, which will reduce the amount of money we have for operations, capital expenditures, expansion, acquisitions or general corporate or other business activities;

- the amount of our interest expense may increase because certain of our borrowings in the future may be at variable rates of interest, which, if interest rates increase, could result in higher interest expense;

- we may have a higher level of debt than some of our competitors, which may put us at a competitive disadvantage;

- we may be more vulnerable to economic downturns and adverse developments in our industry or the economy in general, especially extended or further declines in oil and natural gas prices; and

- our debt level could limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate.

Under the indenture governing our 10 3/8% notes, we will not be able to incur additional secured indebtedness under our bank credit facility if at the time of such incurrence the total amount of indebtedness under our bank credit facility is in excess of the greater of (i) $75 million and (ii) 20% of our ACNTA (as defined in the indenture). Based on the $29 million of borrowings outstanding at December 31, 2009 under our bank credit facility, the indenture would limit our additional borrowings under our bank credit facility to approximately $46 million.

Our ability to meet our expenses and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as economic conditions and governmental regulation. We cannot be certain that our cash flow from operations will be sufficient to allow us to pay the principal and interest on our debt, including our 10 3/8% notes, and meet our other obligations. If we do not have enough cash to service our debt, we may be required to refinance all or part of our existing debt, including our 10 3/8% notes, sell assets, borrow more money or raise equity. We may not be able to refinance our debt, sell assets, borrow more money or raise equity on terms acceptable to us, if at all.

To service our indebtedness, we will require a significant amount of cash. Our ability to generate cash depends on many factors beyond our control, and any failure to meet our debt obligations could harm our business, financial condition and results of operations.

Our ability to make payments on and to refinance our indebtedness, including our 10 3/8% notes, and to fund planned capital expenditures will depend on our ability to generate sufficient cash flow from operations in the future. To a certain extent, this is subject to general economic, financial, competitive, legislative and regulatory conditions and other factors that are beyond our control, including the prices that we receive for our oil and natural gas production.

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 bank credit facility in an amount sufficient to enable us to pay principal and interest on our indebtedness, including our 10 3/8% notes, or to fund our other liquidity needs. If our cash flow and capital resources are insufficient to fund our debt obligations, we may be forced to reduce our planned capital expenditures, sell assets, seek additional equity or debt capital or restructure our debt. We cannot assure you that any of these remedies could, if necessary, be affected on commercially reasonable terms, or at all. In addition, any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms. Our cash flow and capital resources may be insufficient for payment of interest on and principal of our debt in the future, including payments on our 10 3/8% notes, and any such alternative measures may be unsuccessful or may not permit us to meet scheduled debt service obligations, which could cause us to default on our obligations and could impair our liquidity.

The recent financial crisis and continuing uncertain economic conditions may have material adverse impacts on our business and financial condition that we currently cannot predict.

As widely reported, financial markets in the United States, Europe and Asia recently experienced a period of unprecedented turmoil and upheaval characterized by extreme volatility and declines in security prices, severely diminished liquidity and credit availability, inability to access capital markets, the bankruptcy, failure, collapse or sale of various financial institutions and an unprecedented level of intervention from the United States federal government and other governments. Due to the recent financial crisis and continuing uncertain economic conditions, the demand for oil and natural gas has declined, which has negatively impacted the revenues, margins and profitability of our business. In addition, the borrowing base under our bank credit facility has been reduced as a result of redeterminations due to lower oil and gas prices. Unemployment has risen while business and consumer confidence have declined.

Although we cannot predict the additional impacts on us of continuing uncertain economic conditions, they could materially adversely affect our business and financial condition. For example:

- the demand for oil and natural gas may decline due to continuing uncertain economic conditions which could negatively impact the revenues, margins and profitability of our oil and natural gas business;
- our ability to access the capital markets may be restricted at a time when we would like, or need, to raise capital for our business including for exploration and/or development of our reserves;
- the tightening of credit or lack of credit availability to our customers could adversely affect our ability to collect our trade receivables; or
- counterparties may not fulfill their delivery or purchase obligations.

Lower oil and natural gas prices may cause us to record ceiling test write-downs, which could negatively impact our results of operations.

We use the full cost method of accounting to account for our oil and natural gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop oil and natural gas properties. Under full cost accounting rules, the net capitalized costs of oil and natural gas properties may not exceed a "full cost ceiling" which is based upon the present value of estimated future net cash flows from proved reserves, including the effect of hedges in place, discounted at 10%, plus the lower of cost or fair market value of unproved properties. If at the end of any fiscal period we determine that the net capitalized costs of oil and natural gas properties exceed the full cost ceiling, we must charge the amount of the excess to earnings in the period then ended. This is called a "ceiling test write-down." This charge does not impact cash flow from operating activities, but does reduce our net income and stockholders' equity. Once incurred, a write-down of oil and natural gas properties is not reversible at a later date. During 2009, we recognized approximately $156.1 million in ceiling test write-downs as a result of the decline in commodity prices.

We review the net capitalized costs of our properties quarterly, using, effective for fiscal periods ending on or after December 31, 2009, a single price based on the beginning of the month average of oil and natural gas prices for the prior 12 months. We also assess investments in unproved properties periodically to determine whether impairment has occurred. The risk that we will be required to further write down the carrying value of our oil and gas properties increases when oil and natural gas prices are low or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves or our unproved property values, or if estimated future development costs increase. We may experience further ceiling test write-downs or other impairments in the future. In addition, any future ceiling test cushion would be subject to fluctuation as a result of acquisition or divestiture activity.

We may not be able to obtain adequate financing to execute our long-term operating strategy when the need arises.

Our ability to execute our long-term operating strategy is highly dependent on our having access to capital when the need arises. We have historically addressed our long-term liquidity needs through the use of bank credit facilities, second lien term credit facilities, the issuance of equity and debt securities, the use of proceeds from the sale of assets and the use of cash provided by operating activities. We will examine the following alternative sources of long-term capital as dictated by current economic conditions:

- borrowings from banks or other lenders;
- the issuance of debt securities;
- the sale of common stock, preferred stock or other equity securities;
- joint venture financing; and
- production payments.

The availability of these sources of capital when the need arises will depend upon a number of factors, some of which are beyond our control. These factors include general economic and financial market conditions, oil and natural gas prices, our credit ratings, interest rates, market perceptions of us or the oil and gas industry, our market value and operating performance. We may be unable to execute our long-term operating strategy if we cannot obtain capital from these sources when the need arises.

We may not be able to fund our planned capital expenditures.

Although our capital expenditure budget is forecasted to remain within our cash flow for 2010, we will continue to spend a substantial amount of capital for the development, exploration, acquisition and production of oil and natural gas reserves. If extended or further declines in oil and natural gas prices, operating difficulties or other factors, many of which are beyond our control, cause our revenues or cash flows from operations to decrease, we may be limited in our ability to spend the capital necessary to execute our drilling program. We may be forced to raise additional debt or equity, sell properties or assets or enter into joint venture arrangements with industry partners to fund such expenditures. We cannot assure you that additional financings or cash generated by operations will be available to meet these requirements.

Restrictive debt covenants could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

Our bank credit facility and the indenture governing our 10 3/8% notes contain a number of significant covenants that, among other things, restrict or limit our ability to:

- dispose of assets;
- incur a certain level of borrowings under our credit facility and incur or guarantee additional indebtedness and issue certain types of preferred stock;

- pay dividends on our capital stock;
- create liens on our assets;
- enter into sale and leaseback transactions;
- enter into specified investments or acquisitions;
- repurchase, redeem or retire our capital stock or subordinated debt;
- merge or consolidate, or transfer all or substantially all of our assets and the assets of our subsidiaries;
- engage in specified transactions with subsidiaries and affiliates; or
- other corporate activities.

Also, our bank credit facility and the indenture governing our 10 3/8% notes require us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Our ability to comply with these ratios and financial condition tests may be affected by events beyond our control, and we cannot assure you that we will meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under our bank credit facility and the indenture governing our 10 3/8% notes impose on us.

A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition tests could result in a default under our bank credit facility and our 10 3/8% notes. A default, if not cured or waived, could result in acceleration of all indebtedness outstanding under our bank credit facility and our 10 3/8% notes. The accelerated debt would become immediately due and payable. If that should occur, we may not be able to pay all such debt or to borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms that are acceptable to us.

Our future success depends upon our ability to find, develop, produce and acquire additional oil and natural gas reserves that are economically recoverable.

As is generally the case in the Gulf Coast Basin where approximately half of our current production is located, many of our producing properties are characterized by a high initial production rate, followed by a steep decline in production. In order to maintain or increase our reserves, we must constantly locate and develop or acquire new oil and natural gas reserves to replace those being depleted by production. We must do this even during periods of low oil and natural gas prices when it is difficult to raise the capital necessary to finance our exploration, development and acquisition activities. Without successful exploration, development or acquisition activities, our reserves and revenues will decline rapidly. We may not be able to find and develop or acquire additional reserves at an acceptable cost or have access to necessary financing for these activities, either of which would have a material adverse effect on our financial condition.

Approximately half of our production is exposed to the additional risk of severe weather, including hurricanes and tropical storms, as well as flooding, coastal erosion and sea level rise.

Approximately half of our production and approximately 23% of our reserves are located in the Gulf of Mexico and along the Gulf Coast Basin. Operations in this area are subject to severe weather, including hurricanes and tropical storms, as well as flooding, coastal erosion and sea level rise. Some of these adverse conditions can be severe enough to cause substantial damage to facilities and possibly interrupt production. For example, certain of our Gulf Coast Basin properties have experienced damages and production downtime as a result of storms including Hurricanes Katrina and Rita, and more recently Hurricanes Gustav and Ike. In addition, according to certain scientific studies, emissions of carbon dioxide, methane, nitrous oxide and other gases commonly known as greenhouse gases may be contributing to global warming of the earth's atmosphere and to global climate change, which may exacerbate the severity of these adverse conditions. As a result, such conditions may pose increased climate-related risks to our assets and operations.

In accordance with customary industry practices, we maintain insurance against some, but not all, of these risks; however, losses could occur for uninsured risks or in amounts in excess of existing insurance coverage. We cannot assure you that we will be able to maintain adequate insurance in the future at rates we consider reasonable or that any particular types of coverage will be available. An event that is not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

Losses and liabilities from uninsured or underinsured drilling and operating activities could have a material adverse effect on our financial condition and operations.

We maintain several types of insurance to cover our operations, including worker's compensation, maritime employer's liability and comprehensive general liability. Amounts over base coverages are provided by primary and excess umbrella liability policies. We also maintain operator's extra expense coverage, which covers the control of drilling or producing wells as well as redrilling expenses and pollution coverage for wells out of control.

We may not be able to maintain adequate insurance in the future at rates we consider reasonable, or we could experience losses that are not insured or that exceed the maximum limits under our insurance policies. If a significant event that is not fully insured or indemnified occurs, it could materially and adversely affect our financial condition and results of operations.

Factors beyond our control affect our ability to market oil and natural gas.

The availability of markets and the volatility of product prices are beyond our control and represent a significant risk. The marketability of our production depends upon the availability and capacity of natural gas gathering systems, pipelines and processing facilities. The unavailability or lack of capacity of these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Our ability to market oil and natural gas also depends on other factors beyond our control. These factors include:

- the level of domestic production and imports of oil and natural gas;
- the proximity of natural gas production to natural gas pipelines;
- the availability of pipeline capacity;
- the demand for oil and natural gas by utilities and other end users;
- the availability of alternate fuel sources;
- the effect of inclement weather, such as hurricanes;
- state and federal regulation of oil and natural gas marketing; and
- federal regulation of natural gas sold or transported in interstate commerce.

If these factors were to change dramatically, our ability to market oil and natural gas or obtain favorable prices for our oil and natural gas could be adversely affected.

We face strong competition from larger oil and natural gas companies that may negatively affect our ability to carry on operations.

We operate in the highly competitive areas of oil and natural gas exploration, development and production. Factors that affect our ability to compete successfully in the marketplace include:

- the availability of funds and information relating to a property;
- the standards established by us for the minimum projected return on investment; and
- the transportation of natural gas.

Our competitors include major integrated oil companies, substantial independent energy companies, affiliates of major interstate and intrastate pipelines and national and local natural gas gatherers, many of which possess greater financial and other resources than we do. If we are unable to successfully compete against our competitors, our business, prospects, financial condition and results of operations may be adversely affected.

Our estimates of proved reserves have been prepared under revised SEC rules which went into effect for fiscal years ending on or after December 31, 2009, which may make comparisons to prior periods difficult and could limit our ability to book additional proved undeveloped reserves in the future.

This Form 10-K presents estimates of our proved reserves as of December 31, 2009, which have been prepared and presented under revised SEC rules. These revised rules are effective for fiscal years ending on or after December 31, 2009, and require SEC reporting companies to prepare their reserve estimates using revised reserve definitions and revised pricing based on twelve-month unweighted first-day-of-the-month average pricing. The previous rules required that reserve estimates be calculated using last-day-of-the-year pricing. The pricing that was used for estimates of our reserves as of December 31, 2009 was based on an unweighted average twelve month price, adjusted for field differentials, of $60.57 per Bbl for oil and $2.97 per Mcfe for natural gas, as compared to $41.53 per Bbl for oil and $4.64 per Mcfe for natural gas as of December 31, 2008. As a result of these changes, direct comparisons to our previously-reported reserve amounts may be more difficult.

Another impact of the revised SEC rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This revised rule may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill on those reserves within the required five-year timeframe.

Our actual production, revenues and expenditures related to our reserves are likely to differ from our estimates of proved reserves. We may experience production that is less than estimated and drilling costs that are greater than estimated in our reserve report. These differences may be material.

Although the estimates of our oil and natural gas reserves and future net cash flows attributable to those reserves were prepared by Ryder Scott Company, L.P. and Netherland, Sewell & Associates, Inc., our independent petroleum and geological engineers, we are ultimately responsible for the disclosure of those estimates. Reserve engineering is a complex and subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, including:

- historical production from the area compared with production from other similar producing wells;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning future oil and natural gas prices; and
- assumptions concerning future operating costs, severance and excise taxes, development costs and work-over and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating proved reserves:

- the quantities of oil and natural gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future oil and natural gas sales prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. Historically, the difference between our actual production and the production estimated in a prior year's reserve report has not been material. However, our 2009 production was approximately 10% less than amounts projected in our 2008 reserve report. The lower than estimated production was primarily the result of significant reductions in our 2009 capital expenditures budget in response to lower commodity prices. We cannot assure you that these differences will not be material in the future.

Approximately 38% of our estimated proved reserves at December 31, 2009 are undeveloped and 9% were developed, non-producing. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to develop and produce our reserves. Although we have prepared estimates of our oil and natural gas reserves and the costs associated with these reserves in accordance with industry standards, we cannot assure you that the estimated costs are accurate, that development will occur as scheduled or that the actual results will be as estimated. In addition, the recovery of undeveloped reserves is generally subject to the approval of development plans and related activities by applicable state and/or federal agencies. Statutes and regulations may affect both the timing and quantity of recovery of estimated reserves. Such statutes and regulations, and their enforcement, have changed in the past and may change in the future, and may result in upward or downward revisions to current estimated proved reserves.

You should not assume that the standardized measure of discounted cash flows is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, the standardized measure of discounted cash flows from proved reserves at December 31, 2009 are based on twelve-month average prices and costs as of the date of the estimate. These prices and costs will change and may be materially higher or lower than the prices and costs as of the date of the estimate. Any changes in consumption by oil and natural gas purchasers or in governmental regulations or taxation may also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor we use when calculating standardized measure of discounted cash flows for reporting requirements in compliance with accounting requirements is not necessarily the most appropriate discount factor. The effective interest rate at various times and the risks associated with our operations or the oil and natural gas industry in general will affect the accuracy of the 10% discount factor.

We may be unable to successfully identify, execute or effectively integrate future acquisitions, which may negatively affect our results of operations.

Acquisitions of oil and gas businesses and properties have been an important element of our business, and we will continue to pursue acquisitions in the future. In the last several years, we have pursued and consummated acquisitions that have provided us opportunities to grow our production and reserves. Although we regularly engage in discussions with, and submit proposals to, acquisition candidates, suitable acquisitions may not be available in the future on reasonable terms. If we do identify an appropriate acquisition candidate, we may be unable to successfully negotiate the terms of an acquisition, finance the acquisition or, if the acquisition occurs, effectively integrate the acquired business into our existing business. Negotiations of potential acquisitions and the integration of acquired business operations may require a disproportionate amount of management's attention and our resources. Even if we complete additional acquisitions, continued acquisition financing may not be available or available on reasonable terms, any new businesses may not generate revenues comparable to our existing business, the anticipated cost efficiencies or synergies may not be realized and these businesses may not be integrated successfully or operated profitably. The success of any acquisition will depend on a number of factors, including the ability to estimate accurately the recoverable volumes of reserves, rates of future production and future net revenues attainable from the reserves and to assess possible environmental liabilities. Our inability to successfully identify, execute or effectively integrate future acquisitions may negatively affect our results of operations.

Even though we perform due diligence reviews (including a review of title and other records) of the major properties we seek to acquire that we believe is consistent with industry practices, these reviews are inherently incomplete. It is generally not feasible for us to perform an in-depth review of every individual property and all records involved in each acquisition. However, even an in-depth review of records and properties may not necessarily reveal existing or potential problems or permit us to become familiar enough with the properties to assess fully their deficiencies and potential. Even when problems are identified, we may assume certain environmental and other risks and liabilities in connection with the acquired businesses and properties. The discovery of any material liabilities associated with our acquisitions could harm our results of operations.

In addition, acquisitions of businesses may require additional debt or equity financing, resulting in additional leverage or dilution of ownership. Our bank credit facility contains certain covenants that limit, or which may have the effect of limiting, among other things acquisitions, capital expenditures, the sale of assets and the incurrence of additional indebtedness.

Hedging production may limit potential gains from increases in commodity prices or result in losses.

We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in oil and natural gas prices and to achieve more predictable cash flow. Our hedges at December 31, 2009 are costless collars that are placed with the commodity trading branches of JP Morgan and Wells Fargo, each of whom participates in our bank credit facility. We cannot assure you that these or future counterparties will not become credit risks in the future. Hedging arrangements expose us to risks in some circumstances, including situations when the counterparty to the hedging contract defaults on the contractual obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. These hedging arrangements may limit the benefit we could receive from increases in the market or spot prices for oil and natural gas. Oil and natural gas hedges increased (reduced) our total oil and gas sales by approximately $79.9 million, ($8.3) million and $9.9 million during 2009, 2008 and 2007, respectively. We cannot assure you that the hedging transactions we have entered into, or will enter into, will adequately protect us from fluctuations in oil and natural gas prices.

The loss of key management or technical personnel could adversely affect our ability to operate.

Our operations are dependent upon a diverse group of key senior management and technical personnel. In addition, we employ numerous other skilled technical personnel, including geologists, geophysicists and engineers that are essential to our operations. We cannot assure you that such individuals will remain with us for the immediate or foreseeable future. The unexpected loss of the services of one or more of any of these key management or technical personnel could have an adverse effect on our operations.

Operating hazards may adversely affect our ability to conduct business.

Our operations are subject to risks inherent in the oil and natural gas industry, such as:

- unexpected drilling conditions including blowouts, cratering and explosions;
- uncontrollable flows of oil, natural gas or well fluids;
- equipment failures, fires or accidents;
- pollution and other environmental risks; and
- shortages in experienced labor or shortages or delays in the delivery of equipment.

These risks could result in substantial losses to us from injury and loss of life, damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations. Our offshore operations are also subject to a variety of operating risks peculiar to the marine environment, such as hurricanes or other adverse weather conditions and more extensive governmental regulation. These regulations may, in certain circumstances, impose strict liability for pollution damage or result in the interruption or termination of operations.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Congress is currently considering legislation to amend the federal Safe Drinking Water Act to repeal the exemptions for hydraulic fracturing from the Safe Drinking Water Act and require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of bills currently pending before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. The proposed legislation 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. Further, the legislation could result in an additional level of regulation that could lead to operational delays, increased operating costs and additional regulatory burdens.

Environmental compliance costs and environmental liabilities could have a material adverse effect on our financial condition and operations.

Our operations are subject to numerous federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may:

- require the acquisition of permits before drilling commences;
- restrict the types, quantities and concentration of various substances that can be released into the environment from drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas;
- require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells; and
- impose substantial liabilities for pollution resulting from our operations.

The trend toward stricter standards in environmental legislation and regulation is likely to continue. The enactment of stricter legislation or the adoption of stricter regulations could have a significant impact on our operating costs, as well as on the oil and natural gas industry in general.

Our operations could result in liability for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. We could also be liable for environmental damages caused by previous property owners. As a result, substantial liabilities to third parties or governmental entities may be incurred which could have a material adverse effect on our financial condition and results of operations. We maintain insurance coverage for our operations, including limited coverage for sudden and accidental environmental damages, but this insurance may not extend to the full potential liability that could be caused by sudden and accidental environmental damages and further may not cover environmental damages that occur over time. Accordingly, we may be subject to liability or may lose the ability to continue exploration or production activities upon substantial portions of our properties if certain environmental damages occur.

The Oil Pollution Act of 1990 imposes a variety of regulations on "responsible parties" related to the prevention of oil spills. The implementation of new, or the modification of existing, environmental laws or regulations, including regulations promulgated pursuant to the Oil Pollution Act, could have a material adverse impact on us.

We cannot control the activities on properties we do not operate and we are unable to ensure the proper operation and profitability of these non-operated properties.

We do not operate all of the properties in which we have an interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, the operation of these properties. The success and timing of drilling and development activities on our partially owned properties operated by others therefore will depend upon a number of factors outside of our control, including the operator's:

- timing and amount of capital expenditures;
- expertise and diligence in adequately performing operations and complying with applicable agreements;
- financial resources;
- inclusion of other participants in drilling wells; and
- use of technology.

As a result of any of the above or an operator's failure to act in ways that are in our best interest, our allocated production revenues and results of operations could be adversely affected.

Ownership of working interests and overriding royalty interests in certain of our properties by certain of our officers and directors potentially creates conflicts of interest.

Certain of our executive officers and directors or their respective affiliates are working interest owners or overriding royalty interest owners in certain properties. In their capacity as working interest owners, they are required to pay their proportionate share of all costs and are entitled to receive their proportionate share of revenues in the normal course of business. As overriding royalty interest owners they are entitled to receive their proportionate share of revenues in the normal course of business. There is a potential conflict of interest between us and such officers and directors with respect to the drilling of additional wells or other development operations with respect to these properties.

Risks Relating to Our Outstanding Common Stock

Our stock price could be volatile, which could cause you to lose part or all of your investment.

The stock market has from time to time experienced significant price and volume fluctuations that may be unrelated to the operating performance of particular companies. In particular, the market price of our common stock, like that of the securities of other energy companies, has been and may continue to be highly volatile. During 2009, the sales price of our stock ranged from a low of $0.61 per share (on March 9, 2009) to a high of $8.65 per share (on January 6, 2009). Factors such as announcements concerning changes in prices of oil and natural gas, the success of our acquisition, exploration and development activities, the availability of capital, and economic and other external factors, as well as period-to-period fluctuations and financial results, may have a significant effect on the market price of our common stock.

From time to time, there has been limited trading volume in our common stock. In addition, there can be no assurance that there will continue to be a trading market or that any securities research analysts will continue to provide research coverage with respect to our common stock. It is possible that such factors will adversely affect the market for our common stock.

Issuance of shares in connection with financing transactions or under stock incentive plans will dilute current stockholders.

We have issued 1,495,000 shares of Series B Preferred Stock, which are presently convertible into 5,147,734 shares of our common stock. In addition, pursuant to our stock incentive plan, our management is authorized to grant stock awards to our employees, directors and consultants. You will incur dilution upon the conversion of the Series B Preferred Stock, the exercise of any outstanding stock awards or the grant of any restricted stock. In addition, if we raise additional funds by issuing additional common stock, or securities convertible into or exchangeable or exercisable for common stock, further dilution to our existing stockholders will result, and new investors could have rights superior to existing stockholders.

The number of shares of our common stock eligible for future sale could adversely affect the market price of our stock.

At December 31, 2009, we had reserved approximately 3.2 million shares of common stock for issuance under outstanding options and approximately 5.1 million shares issuable upon conversion of the Series B Preferred Stock. All of these shares of common stock are registered for sale or resale on currently effective registration statements. We may issue additional restricted securities or register additional shares of common stock under the Securities Act in the future. The issuance of a significant number of shares of common stock upon the exercise of stock options, the granting of restricted stock or the conversion of the Series B Preferred Stock, or the availability for sale, or sale, of a substantial number of the shares of common stock eligible for future sale under effective registration statements, under Rule 144 or otherwise, could adversely affect the market price of the common stock.

Provisions in certificate of incorporation, bylaws and shareholder rights plan could delay or prevent a change in control of our company, even if that change would be beneficial to our stockholders.

Certain provisions of our certificate of incorporation, bylaws and shareholder rights plan may delay, discourage, prevent or render more difficult an attempt to obtain control of our company, whether through a tender offer, business combination, proxy contest or otherwise. These provisions include:

- the charter authorization of "blank check" preferred stock;

- provisions that directors may be removed only for cause, and then only on approval of holders of a majority of the outstanding voting stock;
- a restriction on the ability of stockholders to call a special meeting and take actions by written consent; and
- provisions regulating the ability of our stockholders to nominate directors for election or to bring matters for action at annual meetings of our stockholders.

In November 2001, our board of directors adopted a shareholder rights plan, pursuant to which uncertificated preferred stock purchase rights were distributed to our stockholders at a rate of one right for each share of common stock held of record as of November 19, 2001. The rights plan is designed to enhance the board's ability to prevent an acquirer from depriving stockholders of the long-term value of their investment and to protect stockholders against attempts to acquire us by means of unfair or abusive takeover tactics. However, the existence of the rights plan may impede a takeover not supported by our board, including a takeover that may be desired by a majority of our stockholders or involving a premium over the prevailing stock price.

We do not intend to pay dividends on our common stock and our ability to pay dividends on our common stock is restricted.

We have not paid dividends on our common stock, cash or otherwise, and intend to retain our cash flow from operations for the future operation and development of our business. We are currently restricted from paying dividends on our common stock by our bank credit facility, the indenture governing the 10 3/8% senior notes and, in some circumstances, by the terms of our Series B Preferred Stock. Any future dividends also may be restricted by our then-existing debt agreements.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None

ITEM 3. LEGAL PROCEEDINGS

PetroQuest is involved in litigation relating to claims arising out of its operations in the normal course of business, including worker's compensation claims, tort claims and contractual disputes. Some of the existing known claims against us are covered by insurance subject to the limits of such policies and the payment of deductible amounts by us. Management believes that the ultimate disposition of all uninsured or unindemnified matters resulting from existing litigation will not have a material adverse effect on PetroQuest's business or financial position.

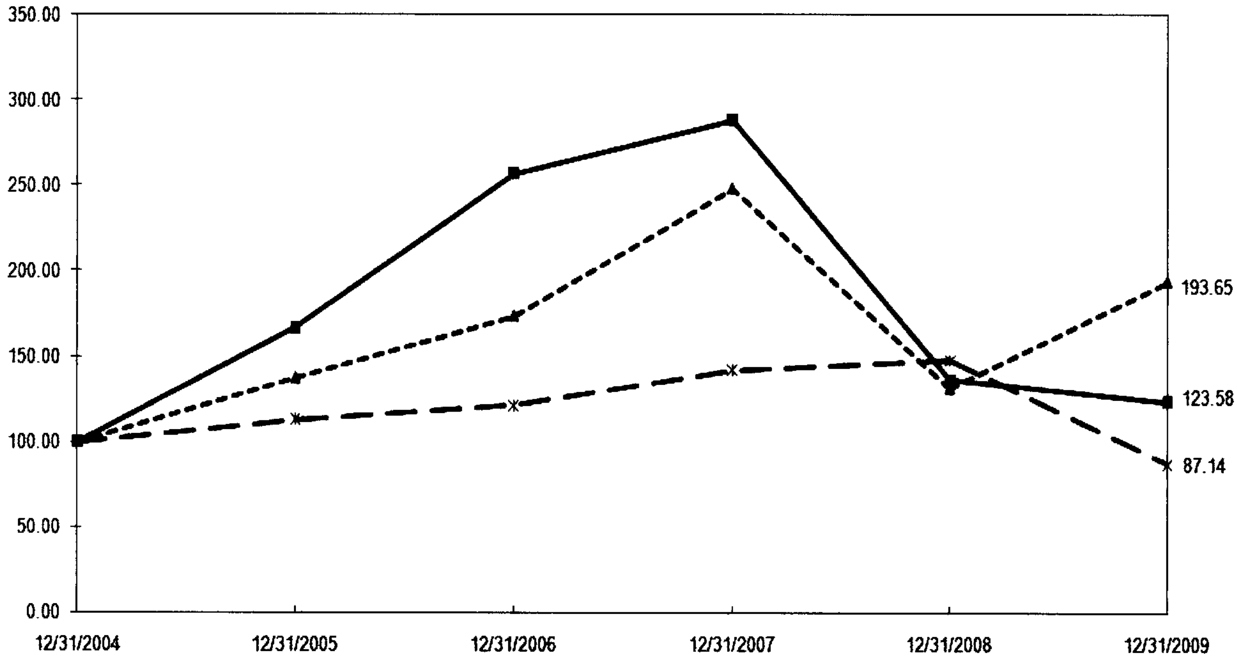
ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

There were no matters submitted to a vote of security holders during the fourth quarter of 2009.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITES

The following graph illustrates the yearly percentage change in the cumulative stockholder return on our common stock, compared with the cumulative total return on the NYSE/AMEX Stock Market (U.S. Companies) Index and the NYSE Stocks - Crude Petroleum and Natural Gas Index, for the five years ended December 31, 2009.



	12/31/2004	12/31/2005	12/31/2006	12/31/2007	12/31/2008	12/31/2009
PetroQuest Energy, Inc.	100.00	166.94	256.85	288.31	136.27	123.58
NYSE/AMEX Stock Market (US Companies)	100.00	113.29	121.38	142.00	147.97	87.14
NYSE Stocks (SIC 1310-1319 US Companies) Crude Petroleum and Natural Gas	100.00	137.51	173.56	247.82	131.34	193.65

Market Price of and Dividends on Common Stock

Our common stock trades on the New York Stock Exchange under the symbol "PQ." The following table lists high and low sales prices per share for the periods indicated:

	High	Low
2008		
1st Quarter	$18.07	$10.77
2nd Quarter	28.16	17.17
3rd Quarter	29.18	13.15
4th Quarter	15.09	4.45
2009		
1st Quarter	$8.65	$0.61
2nd Quarter	5.90	2.14
3rd Quarter	6.52	2.64
4th Quarter	8.08	5.14

As of February 23, 2010, there were 368 common stockholders of record.

We have never paid a dividend on our common stock, cash or otherwise, and intend to retain our cash flow from operations for the future operation and development of our business. In addition, under our bank credit facility, the indenture governing the 10 3/8% senior notes, and, in some circumstances, the terms of our Series B Preferred Stock, we are restricted from paying cash dividends on our common stock. The payment of future dividends, if any, will be determined by our Board of Directors in light of conditions then existing, including our earnings, financial condition, capital requirements, restrictions in financing agreements, business conditions and other factors. See Item 1A. "Risk Factors – Risks Relating to our Outstanding Common Stock – We do not intend to pay dividends on our common stock and our ability to pay dividends on our common stock is restricted."

The following table sets forth certain information with respect to repurchases of our common stock during the quarter ended December 31, 2009.

	Total Number of Shares Purchased (1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan or Program	Maximum Number (or Approximate Dollar Value) of Shares that May be Purchased Under the Plans or Programs
October 1 - October 31, 2009	-	-	-	-
November 1 - November 30, 2009	-	-	-	-
December 1 - December 31, 2009	6,324	$5.39	-	-

(1) All shares repurchased were surrendered by employees to pay tax withholding upon the vesting of restricted stock awards.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth, as of the dates and for the periods indicated, selected financial information for the Company. The financial information for each of the five years in the period ended December 31, 2009 has been derived from the audited Consolidated Financial Statements of the Company for such periods. The information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements and notes thereto. The following information is not necessarily indicative of future results of the Company. All amounts are stated in U.S. dollars unless otherwise indicated.

	Year Ended December 31,				
	2009 (1)	2008 (2)	2007	2006	2005
	(in thousands except per share data)				
Revenues	$ 218,875	$ 313,958	$ 262,334	$ 199,520	$ 120,552
Net income (loss) available to common stockholders	(95,330)	(102,100)	39,245	23,986	21,417
Net income (loss) available to common stockholders per share:					
Basic	(1.72)	(2.08)	0.79	0.49	0.46
Diluted	(1.72)	(2.08)	0.78	0.49	0.44
Oil and gas properties, net	321,875	512,861	554,850	431,814	365,183
Total assets	410,459	670,249	644,347	518,290	431,470
Long-term debt	178,267	278,998	148,755	195,537	158,340
Stockholders' equity	162,105	237,487	302,317	189,711	144,537

(1) The year ended December 31, 2009 includes a ceiling test write-down of $156.1 million.
(2) The year ended December 31, 2008 includes a ceiling test write-down of $266.2 million.

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

Overview

PetroQuest Energy, Inc. is an independent oil and gas company incorporated in the State of Delaware with operations in Oklahoma, Arkansas, Texas and the Gulf Coast Basin. We seek to grow our production, proved reserves, cash flow and earnings at low finding and development costs through a balanced mix of exploration, development and acquisition activities. From the commencement of our operations in 1985 through 2002, we were focused exclusively in the Gulf Coast Basin with onshore properties principally in southern Louisiana and offshore properties in the shallow waters of the Gulf of Mexico shelf. During 2003, we began the implementation of our strategic goal of diversifying our reserves and production into longer life and lower risk onshore properties. As part of the strategic shift to diversify our asset portfolio and lower our geographic and geologic risk profile, we refocused our opportunity selection processes to reduce our average working interest in higher risk projects, shift capital to higher probability of success onshore wells and mitigate the risks associated with individual wells by expanding our drilling program across multiple basins.

Utilizing the cash flow generated by our higher margin Gulf Coast Basin assets, we have successfully diversified into longer life basins in Oklahoma, Arkansas and Texas through a combination of selective acquisitions and drilling activity. Beginning in 2003 with our acquisition of the Carthage Field in Texas through 2009, we have invested approximately $650 million into growing our longer life assets. During the six year period ended December 31, 2009, we have realized a 97% drilling success rate on 551 gross wells drilled. Comparing 2009 metrics with those in 2003, the year we implemented our diversification strategy, we have grown production by 254% and estimated proved reserves by 115%. At December 31, 2009, 77% of our estimated proved reserves and 53% of our 2009 production were derived from our longer life assets.

In response to declining commodity prices and the uncertain outlook on the financial markets as a result of the global financial crisis, during late 2008 we made the decision to shift our focus for 2009 from increasing production and reserves to building liquidity and strengthening our balance sheet. As a result, we reduced our capital expenditures, including capitalized interest and overhead, by 83% in 2009 from $357.8 million in 2008 to $59.1 million in 2009. In addition to reducing our capital expenditures, we also reduced our operating expenses and general and administrative costs, excluding non-cash stock compensation expense, by a combined 21% during 2009 as compared to 2008. Finally, in June 2009 we completed a public offering of 11.5 million shares of our common stock receiving net proceeds of approximately $38 million. As a result of these liquidity building efforts, we repaid $101 million of bank debt in 2009. Despite our reduction in capital expenditures, we were still able to increase production by 1% and only experienced a 3% decline in our estimated proved reserves, as compared to 2008.

Having achieved our 2009 goal of strengthening our balance sheet, we plan to resume our strategy of growing reserves and production during 2010 based upon our outlook for commodity prices. We plan to fund our estimated 2010 capital expenditures budget of $120 - $140 million through internally generated cash flow. We expect to operate the majority of our drilling activity in 2010 which should enable us to respond timely to global market changes and commodity price changes.

Critical Accounting Policies and Estimates

Reserve Estimates

Our estimates of proved oil and gas reserves constitute those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. At the end of each year, our proved reserves are estimated by independent petroleum engineers in accordance with guidelines established by the SEC. These estimates, however, represent projections based on geologic and engineering data. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quantity and quality of available data, engineering and geological interpretation and professional judgment. Estimates of economically recoverable oil and gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effect of regulations by governmental agencies, and assumptions governing future oil and gas prices, future operating costs, severance taxes, development costs and workover costs. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to the extent that these reserves may be later determined to be uneconomic. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of our oil and gas properties and/or the rate of depletion of such oil and gas properties.

On December 29, 2008, the SEC issued a revision to Staff Accounting Bulletin 113 ("SAB 113") which established guidelines related to modernizing accounting and disclosure requirements for oil and natural gas companies. The revised disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. The revised rules also allow companies the option to disclose probable and possible reserves in addition to the existing requirement to disclose proved reserves. The revised disclosure requirements also require companies to report the independence and qualifications of third party preparers of reserves and file reports when a third party is relied upon to prepare reserves estimates. A significant change to the rules involves the pricing at which reserves are measured. The revised rules utilize a 12-month average price using beginning of the month pricing during the 12-month period prior to the ending date of the balance sheet to report oil and natural gas reserves rather than year-end prices. In addition, the 12-month average will also be used to measure ceiling test impairments and to compute depreciation, depletion and amortization. The revised rules are effective for reserve estimation at December 31, 2009 with first reporting for calendar year companies in their 2009 annual reports. See Items 1 and 2 - Business and Properties - Oil and Gas Reserves for a discussion of the impact of this change in methodology on our estimated proved reserves.

Full Cost Method of Accounting

We use the full cost method of accounting for our investments in oil and gas properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of exploring for and developing oil and natural gas are capitalized. Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include the costs of drilling exploratory wells, including those in progress and geological and geophysical service costs in exploration activities. Development costs include the costs of drilling development wells and costs of completions, platforms, facilities and pipelines. Costs associated with production and general corporate activities are expensed in the period incurred. Sales of oil and gas properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas.

The costs associated with unevaluated properties are not initially included in the amortization base and primarily relate to ongoing exploration activities, unevaluated leasehold acreage and delay rentals, seismic data and capitalized interest. These costs are either transferred to the amortization base with the costs of drilling the related well or are assessed quarterly for possible impairment or reduction in value.

We compute the provision for depletion of oil and gas properties using the unit-of-production method based upon production and estimates of proved reserve quantities. Unevaluated costs and related carrying costs are excluded from the amortization base until the properties associated with these costs are evaluated. In addition to costs associated with evaluated properties, the amortization base includes estimated future development costs related to non-producing reserves. Our depletion expense is affected by the estimates of future development costs, unevaluated costs and proved reserves, and changes in these estimates could have an impact on our future earnings.

We capitalize certain internal costs that are directly identified with acquisition, exploration and development activities. The capitalized internal costs include salaries, employee benefits, costs of consulting services and other related expenses and do not include costs related to production, general corporate overhead or similar activities. We also capitalize a portion of the interest costs incurred on our debt. Capitalized interest is calculated using the amount of our unevaluated property and our effective borrowing rate.

Capitalized costs of oil and gas properties, net of accumulated DD&A and related deferred taxes, are limited to the estimated future net cash flows from proved oil and gas reserves, including the effect of cash flow hedges in place, discounted at 10 percent, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (the full cost ceiling). If capitalized costs exceed the full cost ceiling, the excess is charged to write-down of oil and gas properties in the quarter in which the excess occurs.

Natural gas prices have declined significantly since June of 2008. At December 31, 2009, we computed the estimated future net cash flows from our proved oil and gas reserves, discounted at 10%, using twelve-month average prices, including hedges, of $3.10 per Mcfe and $60.57 per barrel. Due to the low twelve-month average prices, we recorded a ceiling test write-down of $52.6 million during the fourth quarter of 2009. Our cash flow hedges in place at December 31, 2009 reduced the fourth quarter ceiling test write-down by approximately $20 million. In total, we recorded $156.1 million in ceiling test write-downs during 2009.

Given the volatility of oil and gas prices, it is probable that our estimate of discounted future net cash flows from proved oil and gas reserves will change in the near term. If oil or gas prices continue to decline, even for only a short period of time, or if we have downward revisions to our estimated proved reserves, it is possible that additional write-downs of oil and gas properties could occur in the future.

Future Abandonment Costs

Future abandonment costs include costs to dismantle and relocate or dispose of our production platforms, gathering systems, wells and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon the type of production structure, depth of water, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including changing technology, the timing of estimated costs, the impact of future inflation on current cost estimates and the political and regulatory environment.

Derivative Instruments

The estimated fair values of our commodity derivative instruments are recorded in the consolidated balance sheet. At inception, all of our commodity derivative instruments represent hedges of the price of future oil and gas production. The changes in fair value of those derivative instruments that qualify for hedge accounting treatment are recorded in other comprehensive income (loss) until the hedged oil or natural gas quantities are produced. If a hedge becomes ineffective because the hedged production does not occur, or the hedge otherwise does not qualify for hedge accounting treatment, the changes in the fair value of the derivative are recorded in the income statement as derivative income or expense.

Our hedges are specifically referenced to NYMEX prices. We evaluate the effectiveness of our hedges at the time we enter the contracts, and periodically over the life of the contracts, by analyzing the correlation between NYMEX prices and the posted prices we receive from our designated production. Through this analysis, we are able to determine if a high correlation exists between the prices received for the designated production and the NYMEX prices at which the hedges will be settled. At December 31, 2009, our derivative instruments were considered effective cash flow hedges.

Estimating the fair value of derivative instruments requires valuation calculations incorporating estimates of future NYMEX prices, discount rates and price movements. As a result, we calculate the fair value of our commodity derivatives using an independent third-party's valuation model that utilizes market-corroborated inputs that are observable over the term of the derivative contract. Our fair value calculations also incorporate an estimate of the counterparties' default risk for derivative assets and an estimate of our default risk for derivative liabilities.

New Accounting Standards

In June 2009, the FASB issued Accounting Standards Update No. 2009-01, "Generally Accepted Accounting Principles" (ASC Topic 105) which establishes the FASB Accounting Standards Codification ("the Codification" or "ASC") as the official single source of authoritative U.S. generally accepted accounting principles ("GAAP"). All existing accounting standards are superseded. All other accounting guidance not included in the Codification is considered non-authoritative.

The Codification is not intended to change GAAP, but it will change the way GAAP is organized and presented. The Codification was effective for our third-quarter 2009 financial statements and the principal impact on our financial statements is limited to disclosures therein as all future references to authoritative accounting literature will be referenced in accordance with the Codification. In order to ease the transition to the Codification, we are providing cross-references to the standards issued and adopted prior to the adoption alongside the Codification references.

Effective January 1, 2009, we adopted ASC Topic 815 (SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities-an amendment of FASB Statement No.133"). ASC Topic 815 requires enhanced disclosures about derivative and hedging activities, and is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The adoption of ASC Topic 815 had no impact on our financial position or results of operations.

Effective January 1, 2009, we adopted ASC Topic 260-10-45 (FSP 03-6-1). ASC Topic 260-10-45 provides that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of earnings per share using the two-class method described in ASC Topic 260-10 (SFAS 128). See Note 4 regarding the impact of the adoption on our calculation of earnings per share.

In April 2009, the FASB issued ASC Topic 825-10-65 (FSP FAS 107-1) and ASC Topic 270 (APB 28-1, "Interim Disclosures about Fair Value of Financial Instruments") which enhance consistency in financial reporting by increasing the frequency of fair value disclosures. These standards are effective for interim and annual periods ending after June 15, 2009 and we adopted the provisions of these standards for the period ending June 30, 2009. The adoption of these standards did not have a material impact on our financial position or results of operations.

We adopted ASC Topic 855 (SFAS No. 165, "Subsequent Events") in the second quarter of 2009. ASC Topic 855 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Although there is new terminology, the standard is based on the same principles as those that previously existed. ASC Topic 855 includes a new required disclosure of the date through which an entity has evaluated subsequent events. The adoption of ASC Topic 855 did not have an impact on our financial position or results of operations.

Results of Operations

The following table sets forth certain operating information with respect to our oil and gas operations for the years ended December 31, 2009, 2008 and 2007. Our historical results are not necessarily indicative of results to be expected in future periods.

	Year Ended December 31,		
	2009	2008	2007
Production:			
Oil (Bbls)	600,124	680,571	1,079,672
Gas (Mcfe)	30,598,092	29,708,204	24,965,789
Total Production (Mcfe)	34,198,836	33,791,630	31,443,821
Sales:			
Total oil sales	$ 41,150,657	$ 66,349,344	$ 76,138,234
Total gas sales	177,493,256	242,273,860	180,084,794
Total oil and gas sales	$ 218,643,913	$ 308,623,204	$ 256,223,028
Average sales prices:			
Oil (per Bbl)	$ 68.57	$ 97.49	$ 70.52
Gas (per Mcfe)	5.80	8.16	7.21
Per Mcfe	6.39	9.13	8.15

The above sales and average sales prices include increases (reductions) to revenue related to the settlement of gas hedges of $74,333,000, ($6,160,000), and $10,713,000 and oil hedges of $5,559,000, ($2,124,000) and ($791,000) for the years ended December 31, 2009, 2008 and 2007, respectively.

Comparison of Results of Operations for the Years Ended December 31, 2009 and 2008

Net loss available to common stockholders totaled ($95,330,000) and ($102,100,000) for the years ended December 31, 2009 and 2008, respectively. The decline in the net loss during 2009 was primarily attributable to the following:

Production Gas production during the twelve-month period ended December 31, 2009 increased 3% from the comparable period in 2008. The increase in gas production was primarily the result of a full year of production from discoveries at our Pelican Point and The Bluffs prospects in South Louisiana and increased production from our Oklahoma and Arkansas wells.

Oil production during the year ended December 31, 2009 decreased 12% from the comparable 2008 period primarily due to normal production declines at our Ship Shoal 72 and Turtle Bayou Fields which produce approximately half of our total oil production.

While production increased overall by 1% in 2009, we experienced declines in each quarter throughout 2009 as a result of our reduced capital expenditures. Our capital expenditure budget for 2010 is significantly increased, which we expect will provide us with quarterly production growth in 2010, as compared to our fourth quarter 2009 production. However, in total, we expect 2010 production to be slightly less than volumes produced during 2009.

Prices Including the effects of our hedges, average oil prices per barrel during 2009 were $68.57, as compared to $97.49 during 2008. Average gas prices per Mcf were $5.80 during 2009, as compared to $8.16 during 2008. Stated on an Mcfe basis, unit prices received during 2009 were 30% lower than the prices received during 2008. See “Liquidity and Capital Resources” below for a discussion of the impact of oil and gas prices on our revenues, cash flow and bank credit facility.

Revenue Including the $79,892,000 received from our hedges, oil and gas sales during the year ended December 31, 2009 totaled $218,644,000, a 29% decrease from oil and gas sales of $308,623,000 during 2008. The decreased revenue during 2009 was primarily the result of lower average pricing and decreased oil production. As a result of the expiration of our higher valued 2009 hedge positions, we expect oil and gas revenue to decline during 2010, as compared to 2009.

Expenses Lease operating expenses for year ended December 31, 2009 decreased to $38,541,000 from $44,665,000 during 2008. Per unit lease operating expenses totaled $1.13 per Mcfe during 2009 as compared to $1.32 per Mcfe during 2008. The decreases in lease operating expenses were primarily due to the decline in costs of services and materials in the markets in which we operate as the demand for such materials and services has weakened as a result of the decline in commodity prices and the overall condition of the oil and gas industry and the global economy. We expect that lease operating expenses during 2010 will approximate those in 2009.

Production taxes totaled $4,656,000 and $12,292,000 during 2009 and 2008, respectively. Production taxes decreased in 2009 for the following reasons. During the third quarter of 2009, we filed for a production tax refund in the amount of $1,144,000 at our Pelican Point prospect as the well qualified for a deep well severance tax exemption for a period of 24-months from the initial production date of May 2008. In addition, we received a production tax refund of $570,000 during the second quarter of 2009 related to certain of our horizontal wells in Oklahoma that qualify for a 48-month production tax exemption. Finally, the impact of lower commodity prices realized for the production from our Oklahoma, Arkansas and Texas properties contributed to the decline in production taxes during the 2009 period. Partially offsetting these decreases was a 15% increase in the Louisiana gas severance tax rate effective July 1, 2009. Because we do not anticipate receiving the same level of production tax refunds in 2010 as we did in 2009, we expect 2010 production taxes to increase.

General and administrative expenses during 2009 totaled $18,869,000 as compared to expenses of $23,249,000 during 2008. Included in general and administrative expenses was share-based compensation expense related to ASC Topic 718 (SFAS 123(R) "Share Based Payment"), as follows (in thousands):

	Years Ended December 31, 2009	Years Ended December 31, 2008
Stock options:		
Incentive Stock Options	$ 835	$ 1,316
Non-Qualified Stock Options	2,024	2,729
Restricted stock	3,469	5,537
Share-based compensation	$ 6,328	$ 9,582

We capitalized $9,330,000 of general and administrative costs during the twelve-month period ended December 31, 2009 and $9,888,000 during the comparable 2008 period. The decline in general and administrative expenses during 2009 was, in part, due to lower non-cash share based compensation. In addition, during May 2008, we incurred compensation expense of approximately $2.5 million, or approximately $1.2 million net of capitalization, related to our election to pay employee taxes on the vesting of certain restricted stock grants. No similar expense was incurred during 2009. We expect that 2010 general and administrative expenses will approximate those in 2009.

The price of natural gas used in computing our estimated proved reserves during 2009 had a negative impact on our estimated proved reserves from certain of our longer-life properties and reduced the estimated future net cash flows from our estimated proved reserves. As a result, we recorded non-cash ceiling test write-downs of our oil and gas properties during 2009 totaling $156,134,000. See Note 10, "Ceiling Test" for further discussion of the ceiling test write-downs. By comparison, we recorded non-cash ceiling test write downs of our oil and gas properties during 2008 totaling $266,156,000.

Depreciation, depletion and amortization ("DD&A") expense on oil and gas properties for 2009 totaled $83,613,000, or $2.44 per Mcfe, as compared to $131,348,000, or $3.89 per Mcfe during 2008. The decline in our DD&A per Mcfe was the result of the ceiling test write-downs of a substantial portion of our proved oil and gas properties during 2009 and the fourth quarter of 2008 as a result of lower commodity prices. We expect DD&A to be lower in 2010 as a result of ceiling test write-downs in 2009.

Interest expense, net of amounts capitalized on unevaluated properties, totaled $12,615,000 during 2009 as compared to $9,327,000 during 2008. We capitalized $8,679,000 and $10,525,000 of interest during 2009 and 2008, respectively. The increase in interest expense during the year ended 2009 is due to the increase in our bank debt outstanding during the first nine months of 2009 as compared to the first nine months of 2008. During the second half of 2009, we repaid a total of $101 million of bank borrowings. As a result of this repayment and our expectation that we will fund our 2010 capital expenditures with cash flow from operations, we expect interest in 2010 to be lower than 2009.

Other expense during 2009 includes $5,673,000 related to payments made in connection with a drilling rig contract. As a result of the significant decline in natural gas prices, we elected to idle this drilling rig. Because there are no corresponding assets to record in connection with the fixed payments required under this contract, regardless of actual rig usage, the costs are recorded as a component of other expense. This contract expired during July 2009. No similar expense was incurred during 2008.

Additionally, other expense during 2009 included $913,000 related to drill pipe inventory which was impaired to reflect the lower of cost or market.

Income tax benefit during 2009 totaled $14,635,000 as compared to $55,581,000 during 2008. We typically provide for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, primarily statutory depletion, non-deductible stock compensation expenses and state income taxes.

As a result of the ceiling test write-downs, we have incurred a cumulative three-year loss. As a result of this cumulative loss and the impact it has on the determination of the recoverability of deferred tax assets through future earnings, we established a valuation allowance of $24.6 million as of December 31, 2009. The impact of this valuation allowance is included in our effective tax rate for the year ended December 31, 2009. Our effective tax rate in future periods will be impacted by future adjustments to the valuation allowance.

Comparison of Results of Operations for the Years Ended December 31, 2008 and 2007

Net income (loss) available to common stockholders totaled ($102,100,000) and $39,245,000 for the years ended December 31, 2008 and 2007, respectively. The decline in net income during 2008 was primarily attributable to the following:

Production During September 2008, the majority of our Gulf Coast Basin properties were impacted by Hurricanes Gustav and Ike and we estimate that approximately 2 Bcfe, which would have been produced during the third and fourth quarters of 2008, was shut-in and deferred as a result of the storms. Oil production during the year ended December 31, 2008 decreased 37% from 2007 primarily due to normal production declines at our Ship Shoal 72 and Turtle Bayou Fields, which provided approximately one-half of our total oil production. Hurricane shut-in time also contributed to the decline in oil production.

During late 2007, we began drilling operations on our Arkansas acreage. As a result of production from this new basin and our continued drilling success in longer life basins, where the production is primarily natural gas, our gas production during 2008 increased 19% from the year ended December 31, 2007. The increase in gas production during 2008 was partially offset by the downtime we experienced as a result of the hurricanes. Overall, production during 2008 was 7% higher than in 2007.

Prices Including the effects of our hedges, average oil prices per barrel during 2008 were $97.49, as compared to $70.52 during 2007. Average gas prices per Mcf were $8.16 during 2008, as compared to $7.21 during 2007. Stated on an Mcfe basis, unit prices received during 2008 were 12% higher than the prices received during 2007; however, oil and gas prices declined significantly during the third and fourth quarters of 2008.

Revenue Oil and gas sales during the year ended December 31, 2008 totaled $308,623,000, a 20% increase from oil and gas sales of $256,223,000 during 2007. The increased revenue during 2008 was primarily the result of higher average pricing and increased gas production.

During 2008, we sold the majority of our gas gathering assets located in Oklahoma for net proceeds of $43,170,000 and recorded a $26,812,000 gain. Proceeds from the sale were used to repay a portion of our bank borrowings.

Expenses Lease operating expenses during 2008 increased to $44,665,000, as compared to $31,965,000 during 2007. On a unit of production basis, operating expenses totaled $1.32 per Mcfe and $1.02 per Mcfe during 2008 and 2007, respectively. The increase in lease operating expenses was primarily due to the overall increase in the cost of materials, transportation, fuel and other services during 2008 as compared to 2007.

Production taxes totaled $12,292,000 and $7,859,000 during 2008 and 2007, respectively. The increase in 2008 production taxes is primarily due to higher average prices and increased production from our Oklahoma, Arkansas and Texas properties. Additionally, there was a 7% increase in the Louisiana gas severance tax rate effective July 1, 2008.

General and administrative expenses during 2008 totaled $23,249,000, as compared to expenses of $21,162,000 during 2007. Included in general and administrative expenses was share-based compensation expense relative to ASC Topic 718 (SFAS 123(R) "Share Based Payment") as follows (in thousands):

	Years Ended December 31, 2008	Years Ended December 31, 2007
Stock options:		
Incentive Stock Options	$ 1,316	$ 1,250
Non-Qualified Stock Options	2,729	1,869
Restricted stock	5,537	6,699
Share based compensation	$ 9,582	$ 9,818

Excluding share-based compensation, general and administrative expenses during 2008 increased by 20%, as compared to 2007. Employee-related costs, including our payment of employee taxes for the vesting of certain restricted stock grants, represented the majority of the increase in expenses during 2008.

Depreciation, depletion and amortization ("DD&A") expense on oil and gas properties for 2008 totaled $131,348,000, or $3.89 per Mcfe, as compared to $116,384,000, or $3.70 per Mcfe during 2007. The increase in DD&A expense during 2008 was primarily due to the higher cost of drilling and completion operations during 2008, as compared to 2007, and the negative impact that declining oil and gas prices had on our proved reserves at September 30, 2008 and December 31, 2008.

The prices of oil and natural gas used in computing our estimated proved reserves at September 30, 2008 and December 31, 2008 were substantially below the market prices received during the majority of 2008. The lower oil and natural gas prices had a negative impact on our proved reserves from certain of our longer-life properties and reduced the estimated discounted cash flow from our proved reserves. As a result, we recorded non-cash ceiling test write-downs of our oil and gas properties during 2008 totaling $266,156,000.

Interest expense, net of amounts capitalized on unevaluated properties, totaled $9,327,000 during 2008 as compared to $13,393,000 during 2007. We capitalized $10,525,000 and $6,539,000 of interest during 2008 and 2007, respectively. The increase in the capitalized portion of our interest cost during 2008 was due to the increase in our unevaluated properties, which is primarily the result of leasehold acquisitions made in our longer-life basins.

Income tax expense (benefit) during 2008 totaled ($55,581,000), as compared to $23,664,000 during 2007. The decrease during 2008 is primarily the result of the impact of ceiling test write-downs, offset in part by the gain on the sale of our gas gathering assets. We provide for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, primarily statutory depletion, non-deductible stock compensation expenses and state income taxes.

Liquidity and Capital Resources

We have financed our acquisition, exploration and development activities to date principally through cash flow from operations, bank borrowings, private and public offerings of equity and debt securities and sales of assets. At December 31, 2009, we had a working capital surplus of $24.7 million compared to a surplus of $40.1 million at December 31, 2008.

During 2009, our cash flow from operations in excess of our significantly reduced capital expenditures and the proceeds from our common stock offering in June 2009 were used to repay $101 million in outstanding borrowings under our bank credit facility and reduce our short-term liabilities, primarily our accounts payable to vendors. These uses of working capital, along with the decline in our hedge asset, resulted in a $15.4 million reduction to working capital as of December 31, 2009 as compared to December 31, 2008.

Prices for oil and natural gas are subject to many factors beyond our control such as weather, the overall condition of the global financial markets and economies, relatively minor changes in the outlook of supply and demand, and the actions of OPEC. Oil and natural gas prices have a significant impact on our cash flows available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under our bank credit facility is subject to periodic re-determination based in part on changing expectations of future prices. Lower prices may also reduce the amount of oil and natural gas that we can economically produce. Lower prices and/or lower production may decrease revenues, cash flows and the borrowing base under the bank credit facility, thus reducing the amount of financial resources available to meet our capital requirements. Lower prices and reduced cash flow may also make it difficult to incur debt, including under our bank credit facility, because of the restrictive covenants in the indenture governing the Notes. See "Source of Capital: Debt" below. Our ability to comply with the covenants in our debt agreements is dependent upon the success of our exploration and development program and upon factors beyond our control, such as oil and natural gas prices.

Source of Capital: Operations

Net cash flow from operations decreased from $169,061,000 in 2008 to $121,822,000 during 2009. The decrease in operating cash flow during 2009 was primarily attributable to the impact of lower commodity prices and the timing of payments made to reduce our accounts payable to vendors.

Source of Capital: Debt

During 2005, we issued $150 million in principal amount of our 10 3/8% Senior Notes due 2012 (the "Notes"), which have numerous covenants including restrictions on liens, incurrence of indebtedness, asset sales, dividend payments and other restricted payments. Interest is payable semi-annually on May 15 and November 15. At December 31, 2009, $1.9 million had been accrued in connection with the May 15, 2010 interest payment and we were in compliance with all of the covenants under the Notes.

On October 2, 2008, we entered into the Credit Agreement (the "Credit Agreement") with JPMorgan Chase Bank, N.A., Calyon New York Branch, Bank of America, N.A., Wells Fargo Bank, N.A., and Whitney National Bank. The Credit Agreement provides for a $300 million revolving credit facility that permits borrowings based on the available borrowing base as determined in accordance with the Credit Agreement. The Credit Agreement also allows us to use up to $25 million of the borrowing base for letters of credit. The Credit Agreement matures on February 10, 2012; provided, however, if on or prior to such date we prepay or refinance, subject to certain conditions, the Notes, the maturity date will be extended to October 2, 2013. We had $29 million and $10 million of borrowings outstanding as of December 31, 2009 and February 26, 2010, respectively, under (and no letters of credit issued pursuant to) the Credit Agreement.

The borrowing base under the Credit Agreement is based upon the valuation as of January 1 and July 1 of each year of the reserves attributable to our oil and gas properties. The current borrowing base, which was based upon the valuation of the reserves attributable to our oil and gas property as of July 1, 2009, is $100 million. The next borrowing base redetermination is scheduled to occur by March 31, 2010. We or the lenders may request two additional borrowing base redeterminations each year. Each time the borrowing base is to be redetermined, the administrative agent under the Credit Agreement will propose a new borrowing base as it deems appropriate in its sole discretion, which must be approved by all lenders if the borrowing base is to be increased, or by lenders holding two-thirds of the amounts outstanding under the Credit Agreement if the borrowing base remains the same or is reduced.

The indenture governing the Notes also limits our ability to incur indebtedness under the Credit Agreement. Under the indenture, we will not be able to incur additional secured indebtedness under the Credit Agreement if at the time of such incurrence, the total amount of indebtedness under the Credit Agreement is in excess of the greater of (i) $75 million and (ii) 20% of our ACTNA (as defined in the indenture). That calculation is based primarily on the valuation of our estimated reserves of oil and natural gas using 12 month average commodity prices. Based on the $10 million of borrowings outstanding on February 26, 2010, the indenture limits our additional borrowings under the Credit Agreement to $65 million.

The Credit Agreement is secured by a first priority lien on substantially all of our assets, including a lien on all equipment and at least 85% of the aggregate total value of our oil and gas properties. Outstanding balances under the Credit Agreement bear interest at the alternate base rate ("ABR") plus a margin (based on a sliding scale of 1.625% to 2.625% depending on borrowing base usage) or the adjusted LIBO rate ("Eurodollar") plus a margin (based on a sliding scale of 2.5% to 3.5% depending on borrowing base usage). The alternate base rate is equal to the highest of (i) the JPMorgan Chase prime rate, (ii) the Federal Funds Effective Rate plus 0.5% or (iii) the adjusted LIBO rate plus 1%. For the purposes of the definition of alternative base rate only, the adjusted LIBO rate is equal to the rate at which dollar deposits of $5,000,000 with a one month maturity are offered by the principal London office of JPMorgan Chase Bank, N.A. in immediately available funds in the London interbank market. For all other purposes, the adjusted LIBO rate is equal to the rate at which Eurodollar deposits in the London interbank market for one, two, three or six months (as selected by us) are quoted, as adjusted for statutory reserve requirements for Eurocurrency liabilities. Outstanding letters of credit are charged a participation fee at a per annum rate equal to the margin applicable to Eurodollar loans, a fronting fee and customary administrative fees. In addition, we pay commitment fees of 0.5%.

We are subject to certain restrictive financial covenants under the Credit Agreement, including a maximum ratio of total debt to EBITDAX, determined on a rolling four quarter basis, of 3.0 to 1.0 and a minimum ratio of consolidated current assets to consolidated current liabilities of 1.0 to 1.0, all as defined in the Credit Agreement. The Credit Agreement also includes customary restrictions with respect to debt, liens, dividends, distributions and redemptions, investments, loans and advances, nature of business, international operations and foreign subsidiaries, leases, sale or discount of receivables, mergers or consolidations, sales of properties, transactions with affiliates, negative pledge agreements, gas imbalances and swap agreements. As of December 31, 2009, we were in compliance with all of the covenants contained in the Credit Agreement.

Source of Capital: Issuance of Securities

On June 30, 2009, we received net proceeds of approximately $38 million through the public offering of 11.5 million shares of our common stock, which included the issuance of 1.5 million shares pursuant to the underwriters' over-allotment option.

During April 2009, we filed a universal shelf registration statement to replace our previous registration statement, which was scheduled to expire in April 2009. This replacement registration statement, which was declared effective in July 2009, allows us to publicly offer and sell up to $200 million of any combination of debt securities, shares of common and preferred stock, depositary shares and warrants. The registration statement does not provide any assurance that we will or could sell any such securities.

Source of Capital: Divestitures

We do not budget property divestitures; however, we are continually evaluating our property base to determine if there are assets in our portfolio that no longer meet our strategic objectives. From time to time we may divest certain non-strategic assets in order to provide liquidity to strengthen our balance sheet or capital to be reinvested in higher rate of return projects. In October 2009, we sold a small interest in certain of our Oklahoma assets for approximately $2.6 million in cash. In addition, the purchasers of that interest have agreed to pay a disproportionate share of all capital expenditures in Oklahoma for the next three years. In May 2009, we sold certain of our East Texas oil and gas properties for approximately $4 million. In 2008, we sold the majority of our gas gathering systems located in Oklahoma for $44.4 million. There can be no assurance that we will be able to sell any of our assets in the future.

Use of Capital: Exploration and Development

Our 2010 capital budget, which includes capitalized interest and general and administrative costs, is expected to range between $120 million and $140 million. This represents an approximately 50% increase from capital spending realized in 2009. We plan to continue our strategic focus of funding our drilling expenditures with cash flow from operations. Because we operate the majority of our proved reserves, we expect to be able to control the timing of a substantial portion of our capital investments. As a result of this flexibility, we plan to actively manage our 2010 capital budget to stay within our projected cash flow from operations, based upon our expectations of commodity prices, production rates and capital costs.

However, if commodity prices decline or if actual production or costs vary significantly from our expectations, our 2010 exploration and development activities could be reduced or could require additional financings, which may include sales of equity or debt securities, sales of properties or assets or joint venture arrangements with industry partners. We cannot assure you that such additional financings will be available on acceptable terms, if at all. If we are unable to obtain additional financing, we could be forced to further delay, reduce our participation in or even abandon some of our exploration and development opportunities or be forced to sell some of our assets on an untimely or unfavorable basis.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2009 (in thousands):

	Total	2010	2011	2012	2013	2014	After 2014
10 3/8% senior notes (1)	$ 186,962	$ 15,563	$ 15,563	$ 155,836	$ -	$ -	$ -
Bank debt (1)	30,927	870	943	29,114	-	-	-
Operating leases (2)	2,793	1,087	894	749	63	-	-
Capital projects (3)	23,916	4,517	1,703	1,267	1,486	682	14,261
Total	$ 244,598	$ 22,037	$ 19,103	$ 186,966	$ 1,549	$ 682	$ 14,261

(1) Includes principal and estimated interest.
(2) Consists primarily of leases for office space and office equipment.
(3) Consists of estimated future obligations to abandon our oil and gas properties.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

We experience market risks primarily in two areas: interest rates and commodity prices. Because all of our properties are located within the United States, we believe that our business operations are not exposed to significant market risks relating to foreign currency exchange risk.

Our revenues are derived from the sale of our crude oil and natural gas production. Based on projected annual sales volumes for 2010, a 10% decline in the estimated average prices we expect to receive for our crude oil and natural gas production would have an approximate $14 million impact on our 2010 revenues.

We periodically seek to reduce our exposure to commodity price volatility by hedging a portion of production through commodity derivative instruments. In the settlement of a typical hedge transaction, we will have the right to receive from the counterparties to the hedge, the excess of the fixed price specified in the hedge over a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the fixed price, we are required to pay the counterparties this difference multiplied by the quantity hedged. During 2009, we received approximately $79.9 million from the counterparties to our derivative instruments in connection with net hedge settlements.

We are required to pay the difference between the floating price and the fixed price (when the floating price exceeds the fixed price) regardless of whether we have sufficient production to cover the quantities specified in the hedge. Significant reductions in production at times when the floating price exceeds the fixed price could require us to make payments under the hedge agreements even though such payments are not offset by sales of production. Hedging will also prevent us from receiving the full advantage of increases in oil or gas prices above the fixed amount specified in the hedge.

Our Credit Agreement requires that the counterparties to our hedge contracts be lenders under the Credit Agreement or, if not a lender under the Credit Agreement, rated A/A2 or higher by S&P or Moody's. Currently, the counterparties to our existing hedge contracts are JP Morgan and Wells Fargo, both of which are lenders under the Credit Agreement. To the extent we enter into additional hedge contracts, we would expect that certain of the lenders under the Credit Agreement would serve as counterparties.

As of December 31, 2009, we had entered into the following gas hedge contracts accounted for as cash flow hedges:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
2010	Costless Collar	30,000 Mmbtu	$5.83 - 6.54

At December 31, 2009, we recognized an asset of approximately $2.8 million related to the estimated fair value of these derivative instruments. Based on estimated future commodity prices as of December 31, 2009, we would realize a $1.8 million gain, net of taxes, as an increase to gas sales during the next 12 months. These gains are expected to be reclassified based on the schedule of gas volumes stipulated in the derivative contracts.

Debt outstanding under our bank credit facility is subject to a floating interest rate and represents 16% of our total debt as of December 31, 2009. Based upon an analysis, utilizing the actual interest rate in effect and balances outstanding as of December 31, 2009, and assuming a 10% increase in interest rates and no changes in the amount of debt outstanding, the potential effect on interest expense for 2010 is less than $100,000.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information concerning this Item begins on page F-1.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, the Company's management, including its Chief Executive Officer and Chief Financial Officer, carried out an evaluation of the effectiveness of the Company's disclosure controls and procedures pursuant to Rule 13a-15 of the Securities and Exchange Act of 1934, as amended (the "Exchange Act"). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded the following:

i. that the Company's disclosure controls and procedures are designed to ensure (a) that information required to be disclosed by the Company in the reports it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms, and (b) that such information is accumulated and communicated to the Company's management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure; and

ii. that the Company's disclosure controls and procedures are effective.

Notwithstanding the foregoing, there can be no assurance that the Company's disclosure controls and procedures will detect or uncover all failures of persons within the Company and its consolidated subsidiaries to disclose material information otherwise required to be set forth in the Company's periodic reports. 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.

Changes in Internal Control Over Financial Reporting

There have been no changes in the Company's internal control over financial reporting during the quarter ended December 31, 2009 that have materially affected, or that are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting, and for performing an assessment of the effectiveness of internal control over financial reporting as of December 31, 2009. 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. Our system of internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (ii) 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 (iii) 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. Projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management performed an assessment of the effectiveness of our internal control over financial reporting as of December 31, 2009 based upon criteria in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our assessment, management believes that our internal control over financial reporting was effective as of December 31, 2009 based on these criteria.

Ernst & Young LLP, our independent registered public accounting firm, has issued their report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2009.

February 26, 2010

/s/ Charles T. Goodson
Charles T. Goodson
Chairman and
Chief Executive Officer

/s/ J. Bond Clement
J. Bond Clement
Executive Vice President-
Chief Financial Officer

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
PetroQuest Energy, Inc.

We have audited PetroQuest Energy, Inc.'s internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). PetroQuest Energy, Inc.'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, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and 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, PetroQuest Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the COSO criteria.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the accompanying consolidated balance sheets of PetroQuest Energy, Inc. as of December 31, 2009 and 2008, and the related consolidated statements of operations, cash flows, stockholders' equity and comprehensive income for each of the three years in the period ended December 31, 2009 and our report dated February 26, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
February 26, 2010

ITEM 9B. OTHER INFORMATION

NONE

PART III

ITEMS 10, 11, 12, 13 & 14

Pursuant to General Instruction G of Form 10-K, the information concerning Item 10. Directors, Executive Officers and Corporate Governance, Item 11. Executive Compensation, Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, Item 13. Certain Relationships and Related Transactions, and Director Independence and Item 14. Principal Accountant Fees and Services, is incorporated by reference to the information set forth in the definitive Proxy Statement of PetroQuest Energy, Inc. relating to the Annual Meeting of Stockholders to be held May 12, 2010, to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 with the Securities and Exchange Commission.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) 1. FINANCIAL STATEMENTS

The following financial statements of the Company and the Report of the Company's Independent Registered Public Accounting Firm thereon are included on pages F-1 through F-24 of this Form 10-K:

Report of Independent Registered Public Accounting Firm
Consolidated Balance Sheets as of December 31, 2009 and 2008
Consolidated Statements of Operations for the three years ended December 31, 2009
Consolidated Statements of Cash Flows for the three years ended December 31, 2009
Consolidated Statements of Stockholders' Equity for the three years ended December 31, 2009
Consolidated Statements of Comprehensive Income for the three years ended December 31, 2009
Notes to Consolidated Financial Statements

2. FINANCIAL STATEMENT SCHEDULES:

All schedules are omitted because the required information is inapplicable or the information is presented in the Financial Statements or the notes thereto.

3. EXHIBITS:

2.1 Plan and Agreement of Merger by and among Optima Petroleum Corporation, Optima Energy (U.S.) Corporation, its wholly-owned subsidiary, and Goodson Exploration Company, NAB Financial L.L.C., Dexco Energy, Inc., American Explorer, L.L.C. (incorporated herein by reference to Appendix G of the Proxy Statement on Schedule 14A filed July 22, 1998).

3.1 Certificate of Incorporation of PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 4.1 to Form 8-K filed September 16, 1998).

3.2 Certificate of Amendment to Certificate of Incorporation dated May 14, 2008 (incorporated herein by reference to Exhibit 3.1 to Form 8-K filed June 23, 2009).

3.3 Bylaws of PetroQuest Energy, Inc., as amended of December 20, 2007 (incorporated herein by reference to Exhibit 3.1 to Form 8-K filed December 21, 2007).

3.4 Certificate of Domestication of Optima Petroleum Corporation (incorporated herein by reference to Exhibit 4.4 to Form 8-K filed September 16, 1998).

	3.5	Certificate of Designations, Preferences, Limitations and Relative Rights of The Series a Junior Participating Preferred Stock of PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit A of the Rights Agreement attached as Exhibit 1 to Form 8-A filed November 9, 2001).
	3.6	Certificate of Designations establishing the 6.875% Series B cumulative convertible perpetual preferred stock, dated September 24, 2007 (incorporated herein by reference to Exhibit 3.1 to Form 8-K filed on September 24, 2007).
	4.1	Rights Agreement dated as of November 7, 2001 between PetroQuest Energy, Inc. and American Stock Transfer & Trust Company, as Rights Agent, including exhibits thereto (incorporated herein by reference to Exhibit 1 to Form 8-A filed November 9, 2001).
	4.2	Form of Rights Certificate (incorporated herein by reference to Exhibit C of the Rights Agreement attached as Exhibit 1 to Form 8-A filed November 9, 2001).
	4.3	Indenture, dated May 11, 2005, among PetroQuest Energy, Inc., PetroQuest Energy, LLC, the Subsidiary Guarantors identified therein, and the Bank of New York Trust Company, N.A. (incorporated herein by reference to Exhibit 4.1 to Form 8-K filed May 11, 2005).
†	10.1	PetroQuest Energy, Inc. 1998 Incentive Plan, as amended and restated effective May 14, 2008 (the "Incentive Plan") (incorporated herein by reference to Appendix A of the Proxy Statement on Schedule 14A filed April 9, 2008).
†	10.2	Form of Incentive Stock Option Agreement for executive officers (including Charles T. Goodson, W. Todd Zehnder, Arthur M. Mixon, III, Daniel G. Fournerat, Stephen H. Green, Mark K. Stover, Dalton F. Smith III and J. Bond Clement) under the Incentive Plan (incorporated herein by reference to Exhibit 10.2 to Form 10-K filed February 27, 2009).
†	10.3	Form of Nonstatutory Stock Option Agreement under the Incentive Plan (incorporated herein by reference to Exhibit 10.3 to Form 10-K filed February 27, 2009).
†	10.4	Form of Restricted Stock Agreement for executive officers (including Charles T. Goodson, W. Todd Zehnder, Arthur M. Mixon, III, Daniel G. Fournerat, Stephen H. Green, Mark K. Stover, Dalton F. Smith III and J. Bond Clement) under the Incentive Plan (incorporated herein by reference to Exhibit 10.4 to Form 10-K filed February 27, 2009).
†	10.5	PetroQuest Energy, Inc. Annual Cash Bonus Plan (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed August 18, 2006).
†	10.6	Amendment to the PetroQuest Energy, Inc. Annual Cash Bonus Plan (incorporated herein by reference to Exhibit 10.7 to Form 8-K filed January 6, 2009).
	10.7	Credit Agreement dated as of October 2, 2008, among PetroQuest Energy, L.L.C., PetroQuest Energy, Inc., JPMorgan Chase Bank, N.A., Calyon New York Branch, Bank of America, N.A., Wells Fargo Bank, N.A., and Whitney National Bank (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed October 6, 2008).
	10.8	First Amendment to Credit Agreement dated as of March 24, 2009, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., TDC Energy LLC, JPMorgan Chase Bank, N.A., Calyon New York Branch, Bank of America, N.A., Wells Fargo Bank, N.A. and Whitney National Bank (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed March 24, 2009).
	10.9	Second Amendment to Credit Agreement dated as of September 30, 2009, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., TDC Energy LLC, JPMorgan Chase Bank, N.A., Calyon New York Branch, Bank of America, N.A., Wells Fargo Bank, N.A. and Whitney National Bank (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed October 1, 2009).

† 10.10 Amended Executive Employment Agreement dated effective as of December 31, 2008, between Charles T. Goodson and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed January 6, 2009).

† 10.11 Amended Executive Employment Agreement dated effective as of December 31, 2008, between W. Todd Zehnder and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed January 6, 2009).

† 10.12 Amended Executive Employment Agreement dated effective as of December 31, 2008, between Arthur M. Mixon, III and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.3 to Form 8-K filed January 6, 2009).

† 10.13 Amended Executive Employment Agreement dated effective as of December 31, 2008, between Daniel G. Fournerat and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.4 to Form 8-K filed January 6, 2009).

† 10.14 Amended Executive Employment Agreement dated effective as of December 31, 2008, between Stephen H. Green and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.5 to Form 8-K filed January 6, 2009).

† 10.15 Amended Executive Employment Agreement dated effective as of December 31, 2008, between Mark K. Stover and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.19 to Form 10-K filed February 27, 2009).

† 10.16 Amended Executive Employment Agreement dated effective as of December 31, 2008, between Dalton F. Smith III and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.20 to Form 10-K filed February 27, 2009).

† 10.17 Amended Executive Employment Agreement dated effective as of December 31, 2008, between J. Bond Clement and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.20 to Form 10-K filed February 27, 2009).

† 10.18 Form of Amended Termination Agreement between the Company and each of its executive officers, including Charles T. Goodson, W. Todd Zehnder, Arthur M. Mixon, III, Daniel G. Fournerat, Stephen H. Green, Mark K. Stover, Dalton F. Smith III and J. Bond Clement (incorporated herein by reference to Exhibit 10.6 to Form 8-K filed January 6, 2009).

† 10.19 Form of Indemnification Agreement between PetroQuest Energy, Inc. and each of its directors and executive officers, including Charles T. Goodson, W. Todd Zehnder, Arthur M. Mixon, III, Daniel G. Fournerat, Stephen H. Green, Mark K. Stover, Dalton F. Smith III, J. Bond Clement, William W. Rucks, IV, E. Wayne Nordberg, Michael L. Finch, W.J. Gordon, III and Charles F. Mitchell, II (incorporated herein by reference to Exhibit 10.21 to Form 10-K filed March 13, 2002).

14.1 Code of Business Conduct and Ethics (incorporated herein by reference to Exhibit 14.1 to Form 10-K filed March 8, 2006).

*21.1 Subsidiaries of the Company.

*23.1 Consent of Independent Registered Public Accounting Firm.

*23.2 Consent of Ryder Scott Company, L.P.

*23.3 Consent of Netherland, Sewell and Associates, Inc.

*31.1 Certification of Chief Executive Officer pursuant to Rule 13-a-14(a) / Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended.

*31.2	Certification of Chief Financial Officer pursuant to Rule 13-a-14(a) / Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended.
*32.1	Certification pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, of Chief Executive Officer.
*32.2	Certification pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, of Chief Financial Officer.
*99.1	Reserve report letter as of December 31, 2009, as prepared by Ryder Scott Company, L.P.
*99.2	Reserve report letter as of December 31, 2009, as prepared by Netherland, Sewell and Associates, Inc.

* Filed herewith.
† Management contract or compensatory plan or arrangement

(b) Exhibits. See Item 15 (a) (3) above.
(c) Financial Statement Schedules. None

GLOSSARY OF CERTAIN OIL AND NATURAL GAS TERMS

The following is a description of the meanings of some of the oil and natural gas used in this Form 10-K.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, of crude oil or other liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Block. A block depicted on the Outer Continental Shelf Leasing and Official Protraction Diagrams issued by the U.S. Minerals Management Service or a similar depiction on official protraction or similar diagrams issued by a state bordering on the Gulf of Mexico.

Btu or British Thermal Unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

Deterministic estimate. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

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

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

Extension well. A well drilled to extend the limits of a known reservoir.

Farm-in or farm-out. An agreement under which the owner of a working interest in a natural gas and oil lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a "farm-in" while the interest transferred by the assignor is a "farm-out."

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Lead. A specific geographic area which, based on supporting geological, geophysical or other data, is deemed to have potential for the discovery of commercial hydrocarbons.

MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. Thousand cubic feet of natural gas.

Mcfe. Thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMBls. Million barrels of crude oil or other liquid hydrocarbons.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

MMcfe. Million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or wells, as the case may be.

Possible reserves. Those additional reserves that are less certain to be recovered than probable reserves.

Probabilistic estimate. The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

Probable reserves. Those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved area. The part of a property to which proved reserves have been specifically attributed.

Proved oil and gas reserves. Those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

Proved properties. Properties with proved reserves.

Reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

Reliable technology. A grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Reserves. Estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Resources. Quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

Service well. A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

Stratigraphic test well. A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production.

Undeveloped oil and gas reserves. Undeveloped oil and gas reserves are reserves of any category 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.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains proved reserves.

Unproved properties. Properties with no proved reserves

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

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, thereunto duly authorized, on February 26, 2010.

PETROQUEST ENERGY, INC.

By: /s/ Charles T. Goodson
CHARLES T. GOODSON
Chairman of the Board, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 26, 2010.

By: /s/ Charles T. Goodson CHARLES T. GOODSON	Chairman of the Board, President, Chief Executive Officer and Director (Principal Executive Officer)
By: /s/ J. Bond Clement J. BOND CLEMENT	Executive Vice President, Chief Financial Officer, Treasurer (Principal Financial and Accounting Officer)
By: /s/ W.J. Gordon, III W.J. GORDON, III	Director
By: /s/ Michael L. Finch MICHAEL L. FINCH	Director
By: /s/ Charles F. Mitchell, II, M.D. CHARLES F. MITCHELL, II, M.D.	Director
By: /s/ E. Wayne Nordberg E. WAYNE NORDBERG	Director
By: /s/ William W. Rucks, IV WILLIAM W. RUCKS, IV	Director

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
PetroQuest Energy, Inc.

We have audited the accompanying consolidated balance sheets of PetroQuest Energy, Inc. as of December 31, 2009 and 2008, and the related consolidated statements of operations, cash flows, stockholders' equity and comprehensive income for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits 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 financial statements referred to above present fairly, in all material respects, the consolidated financial position of PetroQuest Energy, Inc. at December 31, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, in 2009 the Company changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements and changed its method of computing earnings per share.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), PetroQuest Energy, Inc.'s internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
February 26, 2010

PETROQUEST ENERGY, INC.
Consolidated Balance Sheets
(Amounts in Thousands)

	December 31, 2009	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 20,772	$ 23,964
Revenue receivable	16,457	20,074
Joint interest billing receivable	11,792	24,259
Hedging asset	2,796	40,571
Prepaid drilling costs	2,383	11,523
Drilling pipe inventory	19,297	25,898
Other current assets	1,619	1,530
Total current assets	75,116	147,819
Property and equipment:		
Oil and gas properties:		
Oil and gas properties, full cost method	1,296,177	1,225,304
Unevaluated oil and gas properties	108,079	119,847
Accumulated depreciation, depletion and amortization	(1,082,381)	(832,290)
Oil and gas properties, net	321,875	512,861
Gas gathering assets	4,848	4,644
Accumulated depreciation and amortization of gas gathering assets	(1,198)	(900)
Total property and equipment	325,525	516,605
Other assets, net of accumulated depreciation and amortization of $8,342 and $6,237, respectively	9,818	5,825
Total assets	$ 410,459	$ 670,249
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable to vendors	$ 27,113	$ 70,643
Advances from co-owners	3,662	5,349
Oil and gas revenue payable	7,886	15,305
Accrued interest and preferred stock dividend	3,133	3,696
Asset retirement obligation	4,517	8,590
Other accrued liabilities	4,106	4,094
Total current liabilities	50,417	107,677
Bank debt	29,000	130,000
10 3/8% Senior Notes	149,267	148,998
Asset retirement obligation	19,399	17,043
Deferred income taxes	-	28,845
Other liabilities	271	199
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $.001 par value; authorized 5,000 shares; issued and outstanding 1,495 shares	1	1
Common stock, $.001 par value; authorized 150,000 shares; issued and outstanding 61,177 and 49,319 shares, respectively	61	49
Paid-in capital	259,981	216,253
Accumulated other comprehensive income	1,768	25,560
Accumulated deficit	(99,706)	(4,376)
Total stockholders' equity	162,105	237,487
Total liabilities and stockholders' equity	$ 410,459	$ 670,249

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.

Consolidated Statements of Operations

(Amounts in Thousands, Except Per Share Data)

	Year Ended December 31, 2009	2008	2007
Revenues:			
Oil and gas sales	$ 218,644	$ 308,623	$ 256,223
Gas gathering revenue	231	5,335	6,111
	218,875	313,958	262,334
Expenses:			
Lease operating expenses	38,541	44,665	31,965
Production taxes	4,656	12,292	7,859
Depreciation, depletion and amortization	84,772	134,340	119,969
Ceiling test writedown	156,134	266,156	-
Gas gathering costs	191	2,309	4,120
General and administrative	18,869	23,249	21,162
Accretion of asset retirement obligation	2,452	1,317	923
Interest expense	12,615	9,327	13,393
	318,230	493,655	199,391
Gain on sale of assets	485	26,812	-
Other income (expense)	(5,955)	344	1,340
Income (loss) from operations	(104,825)	(152,541)	64,283
Income tax expense (benefit)	(14,635)	(55,581)	23,664
Net income (loss)	(90,190)	(96,960)	40,619
Preferred stock dividend	5,140	5,140	1,374
Net income (loss) available to common stockholders	$ (95,330)	$ (102,100)	$ 39,245
Earnings per common share:			
Basic			
Net income (loss) per share	$ (1.72)	$ (2.08)	$ 0.79
Diluted			
Net income (loss) per share	$ (1.72)	$ (2.08)	$ 0.78
Weighted average number of common shares:			
Basic	55,363	48,971	48,108
Diluted	55,363	48,971	49,164

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
Consolidated Statements of Cash Flows
(*Amounts in Thousands*)

	Year Ended December 31,		
	2009	2008	2007
Cash flows from operating activities:			
Net income (loss)	$ (90,190)	$ (96,960)	$ 40,619
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Deferred tax expense (benefit)	(14,635)	(55,581)	23,664
Depreciation, depletion and amortization	84,772	134,340	119,969
Ceiling test writedown	156,134	266,156	-
Gain on sale of assets	(485)	(26,812)	-
Accretion of asset retirement obligation	2,452	1,317	923
Pipe inventory impairment	913	-	-
Share-based compensation expense	6,328	9,582	9,818
Amortization costs and other	1,512	1,492	1,187
Payments to settle asset retirement obligations	(1,803)	(19,377)	(6,058)
Changes in working capital accounts:			
Revenue receivable	3,617	2,746	(1,053)
Joint interest billing receivable	11,937	(1,323)	(2,864)
Prepaid drilling and pipe costs	14,828	(35,973)	3,438
Accounts payable and accrued liabilities	(51,375)	(4,567)	37,050
Advances from co-owners	(1,687)	(7,521)	(521)
Other	(496)	1,542	(2,443)
Net cash provided by operating activities	121,822	169,061	223,729
Cash flows from investing activities:			
Investment in oil and gas properties	(63,420)	(325,936)	(233,436)
Investment in gas gathering assets	(204)	(6,204)	(2,968)
Proceeds from sale of gathering assets, net of expenses	-	43,170	-
Proceeds from sale of oil and gas properties and other	7,451	2,256	1,277
Net cash used in investing activities	(56,173)	(286,714)	(235,127)
Cash flows from financing activities:			
Net proceeds from (payments for) share based compensation	(366)	1,597	(99)
Deferred financing costs	(114)	(1,450)	(98)
Proceeds from common stock offering	38,036	-	-
Costs of common stock offering	(258)	-	-
Payment of preferred stock dividend	(5,139)	(5,439)	-
Repayment of bank borrowings	(101,000)	(128,000)	(70,000)
Proceeds from bank borrowings	-	258,000	23,000
Proceeds from preferred stock offering	-	-	74,750
Costs of preferred stock offering	-	-	(4,041)
Net cash provided by (used in) financing activities	(68,841)	124,708	23,512
Net increase (decrease) in cash and cash equivalents	(3,192)	7,055	12,114
Cash and cash equivalents at beginning of period	23,964	16,909	4,795
Cash and cash equivalents at end of period	$ 20,772	$ 23,964	$ 16,909
Supplemental disclosure of cash flow information			
Cash paid during the period for:			
Interest	$ 20,335	$ 17,851	$ 19,238
Income taxes	$ 227	$ -	$ -

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
Consolidated Statements of Stockholders' Equity
(*Amounts in Thousands*)

	Common Stock	Preferred Stock	Paid-In Capital	Other Comprehensive Income (Loss)	Retained Earnings (Deficit)	Total Stockholders' Equity
December 31, 2006	$ 48	$ -	$ 124,552	$ 6,632	$ 58,479	$ 189,711
Options exercised	-	-	1,051	-	-	1,051
Retirement of shares upon vesting of restricted stock	-	-	(1,150)	-	-	(1,150)
Issuance of preferred stock	-	1	70,708	-	-	70,709
Share-based compensation expense	-	-	9,818	-	-	9,818
Derivative fair value adjustment, net of tax	-	-	-	(7,067)	-	(7,067)
Preferred stock dividend	-	-	-	-	(1,374)	(1,374)
Net income	-	-	-	-	40,619	40,619
December 31, 2007	$ 48	$ 1	$ 204,979	$ (435)	$ 97,724	$ 302,317
Options exercised	1	-	1,896	-	-	1,897
Retirement of shares upon vesting of restricted stock	-	-	(300)	-	-	(300)
Share-based compensation expense	-	-	9,582	-	-	9,582
Non-cash compensation	-	-	96	-	-	96
Derivative fair value adjustment, net of tax	-	-	-	25,995	-	25,995
Preferred stock dividend	-	-	-	-	(5,140)	(5,140)
Net loss	-	-	-	-	(96,960)	(96,960)
December 31, 2008	$ 49	$ 1	$ 216,253	$ 25,560	$ (4,376)	$ 237,487
Options exercised	-	-	65	-	-	65
Retirement of shares upon vesting of restricted stock	-	-	(431)	-	-	(431)
Issuance of common stock	12	-	37,766	-	-	37,778
Share-based compensation expense	-	-	6,328	-	-	6,328
Derivative fair value adjustment, net of tax	-	-	-	(23,792)	-	(23,792)
Preferred stock dividend	-	-	-	-	(5,140)	(5,140)
Net loss	-	-	-	-	(90,190)	(90,190)
December 31, 2009	$ 61	$ 1	$ 259,981	$ 1,768	$ (99,706)	$ 162,105

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.

Consolidated Statements of Comprehensive Income

(*Amounts in Thousands*)

	Year Ended December 31,		
	2009	2008	2007
Net income (loss)	$ (90,190)	$ (96,960)	$ 40,619
Change in fair value of derivative instruments, accounted for as hedges, net of tax benefit (expense) of $13,983, ($15,267) and $4,150, respectively	(23,792)	25,995	(7,067)
Comprehensive income (loss)	$ (113,982)	$ (70,965)	$ 33,552

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 - Organization and Summary of Significant Accounting Policies

PetroQuest Energy, Inc. (a Delaware Corporation) ("PetroQuest" or the "Company") is an independent oil and gas company headquartered in Lafayette, Louisiana with exploration offices in Houston, Texas and Tulsa, Oklahoma. It is engaged in the exploration, development, acquisition and operation of oil and gas properties in Oklahoma, Arkansas and Texas as well as onshore and in the shallow waters offshore the Gulf Coast Basin.

Principles of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its subsidiaries, PetroQuest Energy, L.L.C., PetroQuest Oil & Gas, L.L.C, Pittrans, Inc. and TDC Energy LLC. All intercompany accounts and transactions have been eliminated.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reserve Estimates and Oil and Gas Properties

On December 29, 2008, the SEC adopted revised rules related to modernizing accounting and disclosure requirements for oil and natural gas companies. The revised disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. The revised rules also allow companies the option to disclose probable and possible reserves in addition to the existing requirement to disclose proved reserves. The revised disclosure requirements also require companies to report the independence and qualifications of third party preparers of reserves and file reports when a third party is relied upon to prepare reserves estimates. A significant change to the rules involves the pricing at which reserves are measured. The revised rules utilize a 12-month average price using beginning of the month pricing during the 12-month period prior to the ending date of the balance sheet to report oil and natural gas reserves rather than year-end prices. In addition, the 12-month average will also be used to measure ceiling test impairments and to compute depreciation, depletion and amortization. The revised rules were effective for reserves estimated at December 31, 2009. See Note 15 regarding the impact of the adoption on the Company's calculation of reserve estimates and on the Company's financial position and results of operations.

The Company utilizes the full cost method of accounting, which involves capitalizing all acquisition, exploration and development costs incurred for the purpose of finding oil and gas reserves including the costs of drilling and equipping productive wells, dry hole costs, lease acquisition costs and delay rentals. The Company also capitalizes the portion of general and administrative costs, which can be directly identified with acquisition, exploration or development of oil and gas properties. Unevaluated property costs are transferred to evaluated property costs at such time as wells are completed on the properties, the properties are sold, or management determines these costs to have been impaired. Interest is capitalized on unevaluated property costs. Transactions involving sales of reserves in place, unless significant, are recorded as adjustments to accumulated depreciation, depletion and amortization.

Depreciation, depletion and amortization of oil and gas properties is computed using the unit-of-production method based on estimated proved reserves. All costs associated with evaluated oil and gas properties, including an estimate of future development costs associated therewith, are included in the depreciable base. The costs of investments in unproved properties are excluded from this calculation until the costs are evaluated and proved reserves established or impaired. Proved oil and gas reserves are estimated annually by independent petroleum engineers.

The capitalized costs of proved oil and gas properties cannot exceed the present value of the estimated net cash flow from proved reserves based on first of the month average twelve-month oil and gas prices, including the effect of hedges in place (the full cost ceiling). If the capitalized costs of proved oil and gas properties exceed the full cost ceiling, the Company is required to write-down the value of its oil and gas properties to the full cost ceiling amount. The Company follows the provisions of Staff Accounting Bulletin ("SAB") No. 106, regarding the application of ASC Topic 410-20 (SFAS No. 143) by companies following the full cost accounting method. SAB No. 106 indicates that estimated future dismantlement and abandonment costs that are recorded on the balance sheet are to be included in the costs subject to the full cost ceiling limitation. The estimated future cash outflows associated with settling the recorded asset retirement obligations should be excluded from the computation of the present value of estimated future net revenues used in applying the ceiling test. See Note 10 for discussion of ceiling test write-downs recognized during 2009.

Gas Gathering Assets

During 2005, the Company acquired interests in several gas gathering systems used in the transportation of natural gas. The costs related to these systems are depreciated on a straight line basis over their estimated remaining useful lives, generally 14 years. During 2008, the Company sold the majority of its gas gathering assets located in Oklahoma for net proceeds of $43.2 million and recorded a $26.8 million gain.

The net proceeds from the sale were used to repay a portion of the borrowings outstanding under the bank credit facility. The following table summarizes the operating data attributable to the gas gathering systems sold (in thousands):

	Years Ended December 31, 2008	Years Ended December 31, 2007
Gas gathering revenue	$ 4,876	$ 5,581
Expenses:		
Gas gathering costs	(2,247)	(4,120)
Depreciation expense	(1,974)	(2,773)
Income (loss) from operations	$ 655	$ (1,312)

Other Assets

Other assets includes furniture and fixtures (net of accumulated depreciation), which are depreciated over their useful lives ranging from 3-7 years, and deferred financing costs, which are amortized over the life of the related debt. Other assets also includes a long-term receivable of $5.2 million as of December 31, 2009, related to the sale of certain of the Company's interests in oil and gas properties. This amount represents a non-cash investing activity for purposes of the Statement of Cash Flows.

Cash and Cash Equivalents

The Company considers all highly liquid investments with a stated maturity of three months or less to be cash and cash equivalents. The majority of the Company's cash and cash equivalents are in overnight securities made through its commercial bank accounts, which result in available funds the next business day.

Accounts Receivable and Other Accrued Liabilities

In its capacity as operator, the Company incurs drilling and operating costs that are billed to its partners based on their respective working interests. As of December 31, 2009 and 2008, the Company recorded $0.6 million and $0.2 million, respectively, related to an allowance for doubtful accounts. Other accrued liabilities at December 31, 2009 and 2008 included $3.5 million and $2.7 million, respectively, related to accrued estimated incentive compensation costs.

Drilling Pipe Inventory

Drilling pipe inventory, which is included in current assets, consists of tubular goods and pipe that the Company either utilizes in its ongoing exploration and development activities or has available for sale. The cost basis of drilling pipe inventory to be utilized is depreciated as a component of oil and gas properties once the inventory is used in drilling or other capitalized operations. At December 31, 2009, the pipe inventory that the Company has available for sale had a value of $0.5 million, which reflects the lower of cost or market. During 2009, the Company recorded an $0.9 million impairment of inventory as the result of the market value dropping below historical cost related to pipe inventory that is available for sale.

Income Taxes

The Company accounts for income taxes in accordance with ASC Topic 740 (SFAS No. 109, "Accounting for Income Taxes"). Provisions for income taxes include deferred taxes resulting primarily from temporary differences due to different reporting methods for oil and gas properties for financial reporting purposes and income tax purposes. For financial reporting purposes, all exploratory and development expenditures are capitalized and depreciated, depleted and amortized on the unit-of-production method. For income tax purposes, only the equipment and leasehold costs relative to successful wells are capitalized and recovered through depreciation or depletion. Generally, most other exploratory and development costs are charged to expense as incurred; however, the Company may use certain provisions of the Internal Revenue Code which allow capitalization of intangible drilling costs. Other financial and income tax reporting differences occur primarily as a result of statutory depletion.

Revenue Recognition

The Company records natural gas and oil revenue under the sales method of accounting. Under the sales method, the Company recognizes revenues based on the amount of natural gas or oil sold to purchasers, which may differ from the amounts to which the Company is entitled based on its interest in the properties. Gas balancing obligations as of December 31, 2009 and 2008 were not significant.

Certain Concentrations

The Company's production is sold on month to month contracts at prevailing prices. The Company attempts to diversify its sales among multiple purchasers and obtain credit protection such as letters of credit and parental guarantees when necessary.

The following table identifies customers from whom the Company derived 10% or more of its net oil and gas revenues during the years presented. Based on the availability of other customers, the Company does not believe the loss of any of these customers would have a significant effect on its business or financial condition.

	Year Ended December 31,		
	2009	2008	2007
Texon LP	17%	23%	32%
Shell Trading Co.	17%	(a)	(a)
Atmos Energy	13%	(a)	(a)
Laclede Energy	12%	11%	(a)
Louis Dreyfus Corporation	(a)	11%	16%
Crosstex	(a)	11%	(a)
DCP Midstream	(a)	10%	12%

(a) Less than 10 percent

Fair Value of Financial Instruments

The fair value of cash and cash equivalents, accounts receivable and accounts payable approximates book value at December 31, 2009 and 2008 due to the short-term nature of these accounts. The fair value of the bank debt at December 31, 2009 also approximated book value due to the variable rate of interest charged. Hedging instruments are reflected as assets on the balance sheet at estimated fair values of approximately $2.8 million and $40.6 million at December 31, 2009 and 2008, respectively, as required under ASC Topic 815 (SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities"). The estimated fair value of the 10 3/8% senior notes due 2012 (the "Notes") at December 31, 2009 was $150 million, as compared to the book value, net of discount, of $149.3 million. At December 31, 2008, the fair value of the Notes was $103.5 million, while the book value of the Notes, net of discount, was $149 million. The estimated fair value of the Notes was provided by independent brokers using the actual year-end market quote for the Notes.

Derivative Instruments

Under ASC Topic 815 (SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities", as amended), the nature of a derivative instrument must be evaluated to determine if it qualifies for hedge accounting treatment. Instruments qualifying for cash flow hedge accounting treatment are recorded as an asset or liability measured at fair value and subsequent changes in fair value are recognized in stockholders' equity through other comprehensive income (loss), net of related taxes, to the extent the hedge is effective. All of the Company's derivative instruments qualified for cash flow hedge accounting during 2009, 2008 and 2007. As a result, the changes in fair value of these instruments were recorded to other comprehensive income (loss). The cash settlements of cash flow hedges are recorded as adjustments to oil and gas sales. Oil and gas revenues include additions (reductions) related to the net settlement of hedges totaling $79,892,000, ($8,284,000) and $9,922,000 during 2009, 2008 and 2007, respectively. Instruments not qualifying for hedge accounting treatment are recorded on the balance sheet at fair value and changes in fair value are recognized in earnings as derivative expense (income).

The Company's hedges are specifically referenced to NYMEX prices. The effectiveness of hedges is evaluated at the time the contracts are entered into, as well as periodically over the life of the contracts, by analyzing the correlation between NYMEX prices and the posted prices received from the designated production. Through this analysis, the Company is able to determine if a high correlation exists between the prices received for its designated production and the NYMEX prices at which the hedges will be settled. At December 31, 2009, the Company's hedging contracts were considered effective cash flow hedges. See Note 7 for further discussion of the Company's derivative instruments.

New Accounting Standards

In June 2009, the Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update No. 2009-01, "Generally Accepted Accounting Principles" (ASC Topic 105) which establishes the FASB Accounting Standards Codification (the "Codification" or "ASC") as the official single source of authoritative U.S. generally accepted accounting principles ("GAAP"). All existing accounting standards are superseded. All other accounting guidance not included in the Codification is considered non-authoritative.

The Codification is not intended to change GAAP, but it has changed the way GAAP is organized and presented. The Codification was effective for the Company's third-quarter 2009 financial statements and the principal impact on the Company's financial statements is limited to disclosures as all references to authoritative accounting literature were referenced in accordance with the Codification. In order to ease the transition to the Codification, the Company is providing cross-references to the standards issued and adopted prior to the adoption of the Codification alongside the Codification references.

Effective January 1, 2009, the Company adopted ASC Topic 815 (SFAS No. 161 "Disclosures about Derivative Instruments and Hedging Activities-an amendment of SFAS No.133"). ASC Topic 815 requires enhanced disclosures about derivative and hedging activities, and is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The adoption of ASC Topic 815 had no impact on the Company's financial position or results of operations.

Effective January 1, 2009, the Company adopted ASC Topic 260-10-45 (FASB Staff Position ("FSP") No. EITF 03-6-1). ASC Topic 260-10-45 provides that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of earnings per share using the two-class method described in ASC Topic 260-10 (SFAS 128 "Earnings Per Share"). See Note 4 regarding the impact of the adoption on the Company's calculation of earnings per share.

In April 2009, the FASB issued ASC Topic 825-10-65 (FSP FAS 107-1) and ASC Topic 270 (APB 28-1, "Interim Disclosures about Fair Value of Financial Instruments") which enhance consistency in financial reporting by increasing the frequency of fair value disclosures. These standards are effective for interim and annual periods ending after June 15, 2009 and the Company adopted the provisions of these standards for the period ending June 30, 2009. The adoption of these standards did not have a material impact on the Company's financial position or results of operations.

The Company adopted ASC Topic 855 (SFAS No. 165, "Subsequent Events") in the second quarter of 2009. ASC Topic 855 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Although there is new terminology, the standard is based on the same principles as those that previously existed. ASC Topic 855 includes a new required disclosure of the date through which an entity has evaluated subsequent events. The adoption of ASC Topic 855 did not have an impact on the Company's financial position or results of operations.

Note 2 - Convertible Preferred Stock

During 2007, the Company completed the public offering of 1,495,000 shares of its 6.875% Series B cumulative convertible perpetual preferred stock (the "Series B Preferred Stock").

The following is a summary of certain terms of the Series B Preferred Stock:

Dividends. The Series B Preferred Stock will accumulate dividends at an annual rate of 6.875% for each share of Series B Preferred Stock. Dividends will be cumulative from the date of first issuance and, to the extent payment of dividends is not prohibited by the Company's debt agreements, assets are legally available to pay dividends and the Company's board of directors or an authorized committee of the board declares a dividend payable, the Company will pay dividends in cash, every quarter.

Mandatory conversion. On or after October 20, 2010, the Company may, at its option, cause shares of the Series B Preferred Stock to be automatically converted at the applicable conversion rate, but only if the closing sale price of the Company's common stock for 20 trading days within a period of 30 consecutive trading days ending on the trading day immediately preceding the date the Company gives the conversion notice equals or exceeds 130% of the conversion price in effect on each such trading day.

Conversion rights. Each share of Series B Preferred Stock may be converted at any time, at the option of the holder, into 3.4433 shares of the Company's common stock (which is based on an initial conversion price of approximately $14.52 per share of common stock, subject to adjustment) plus cash in lieu of fractional shares, subject to the Company's right to settle all or a portion of any such conversion in cash or shares of the Company's common stock. If the Company elects to settle all or any portion of its conversion obligation in cash, the conversion value and the number of shares of the Company's common stock it will deliver upon conversion (if any) will be based upon a 20 trading day averaging period.

Upon any conversion, the holder will not receive any cash payment representing accumulated and unpaid dividends on the Series B Preferred Stock, whether or not in arrears, except in limited circumstances. The conversion rate is equal to $50 divided by the conversion price at the time. The conversion price is subject to adjustment upon the occurrence of certain events. The conversion price on the conversion date and the number of shares of the Company's common stock, as applicable, to be delivered upon conversion may be adjusted if certain events occur.

Note 3 - Common Stock Offering

On June 30, 2009, the Company received $38 million in net proceeds through the public offering of 11.5 million shares of its common stock, which included the issuance of 1.5 million shares pursuant to the underwriters' over-allotment option.

Note 4 – Earnings Per Share

Effective January 1, 2009, the Company adopted the provisions of ASC Topic 260-10-45 (FSP No. EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities"). As a result of adoption, the Company's earnings per share for 2009 have been calculated in accordance with ASC Topic 260-10-45 and the Company retrospectively adjusted the calculation of earnings per share for the 2008 and 2007 periods. The previously reported basic earnings (loss) per share for 2008 and 2007 were ($2.08) and $0.82, respectively. The previously reported diluted earnings (loss) per share for 2008 and 2007 were ($2.08) and $0.79, respectively.

A reconciliation between basic and diluted earnings (loss) per share computations (in thousands, except per share amounts) is as follows:

For the Year Ended December 31, 2009	Loss (Numerator)	Shares (Denominator)	Per Share Amount
Net loss available to common stockholders	$ (95,330)	55,363	$ (1.72)
Effect of dilutive securities:			
Stock options	-	-	
Restricted stock	-	-	
Series B preferred stock	-	-	
DILUTED EPS	$ (95,330)	55,363	$ (1.72)

For the Year Ended December 31, 2008	Loss (Numerator)	Shares (Denominator)	Per Share Amount
Net loss available to common stockholders	$ (102,100)	48,971	$ (2.08)
Effect of dilutive securities:			
Stock options	-	-	
Restricted stock	-	-	
Series B preferred stock	-	-	
DILUTED EPS	$ (102,100)	48,971	$ (2.08)

For the Year Ended December 31, 2007	Income (Numerator)	Shares (Denominator)	Per Share Amount
BASIC EPS			
Net income available to common stockholders	$ 39,245	48,108	
Attributable to participating securities	(1,069)	-	
BASIC EPS	$ 38,176	48,108	$ 0.79
Effect of dilutive securities:			
Stock options	-	1,056	
Restricted stock	22	-	
Series B preferred stock	-	-	
DILUTED EPS	$ 38,198	49,164	$ 0.78

Common shares issuable upon the assumed conversion of the Series B preferred stock totaling 5,148,000 shares during 2009 and 2008 and 1,364,000 shares during 2007 were not included in the computation of diluted earnings per share because the inclusion would have been anti-dilutive. No restricted stock and stock options were included in the computation of diluted earnings per share for the years ended December 31, 2009 or 2008, respectively, because the inclusion would have been anti-dilutive as a result of the net loss reported for the period. During 2007, there were 155,000 shares that were not included in the computation of diluted earnings per share because the options' exercise prices were in excess of the average market price of the common shares.

Note 5 – Share Based Compensation

The Company accounts for share-based compensation in accordance with ASC Topic 718 (SFAS 123 (revised 2004) "Share Based Payment"). Share-based compensation expense is reflected as a component of the Company's general and administrative expense. A detail of share-based compensation for the years ended December 31, 2009, 2008 and 2007 is as follows (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Stock options:			
Incentive Stock Options	$ 835	$ 1,316	$ 1,250
Non-Qualified Stock Options	2,024	2,729	1,869
Restricted stock	3,469	5,537	6,699
Share based compensation	$ 6,328	$ 9,582	$ 9,818

During the years ended December 31, 2009, 2008 and 2007, the Company recorded income tax benefits of approximately $2 million, $3.1 million and $3.2 million, respectively, related to share based compensation expense recognized during those periods. Any excess tax benefits from the vesting of restricted stock and the exercise of stock options will not be recognized in paid-in capital until the Company is in a current tax paying position. Presently, all of the Company's income taxes are deferred and the Company has net operating losses available to carryover to future periods. Accordingly, no excess tax benefits have been recognized for any periods presented.

At December 31, 2009, the Company had $8.1 million of unrecognized compensation cost related to granted restricted stock and stock options. This amount will be recognized as an expense over a weighted average period of approximately two years.

Stock Options

Stock options generally vest equally over a three-year period, must be exercised within 10 years of the grant date and may be granted only to employees, directors and consultants. The exercise price of each option may not be less than 100% of the fair market value of a share of Common Stock on the date of grant. Upon a change in control of the Company, all outstanding options become immediately exercisable.

The Company computes the fair value of its stock options using the Black-Scholes option-pricing model assuming a stock option forfeiture rate and expected term based on historical activity and expected volatility computed using historical stock price fluctuations on a weekly basis for a period of time equal to the expected term of the option. The Company recognizes compensation expense using the accelerated expense attribution method over the vesting period. Periodically, the Company adjusts compensation expense based on the difference between actual and estimated forfeitures.

The following table outlines the assumptions used in computing the fair value of stock options granted during 2009, 2008 and 2007:

	Years Ended December 31,		
	2009	2008	2007
Dividend yield	0%	0%	0%
Expected volatility	75.5% - 78.4%	54.9% - 69.8%	55.7% - 58.5%
Risk-free rate	2.3% - 2.5%	1.7% - 3.6%	4.0% - 5.1%
Expected term	6 years	6 years	6 years
Forfeiture rate	5.0%	5.0%	5.0%
Stock options granted (1)	638,486	563,900	440,676
Wgtd. avg. grant date fair value per share	$ 4.77	$ 9.45	$ 7.29
Fair value of grants (1)	$ 3,045,000	$ 5,330,000	$ 3,212,000

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(1) Prior to applying estimated forfeiture rate

The following table details stock option activity during the year ended December 31, 2009:

	Number of Options	Wgtd. Avg. Exercise Price	Wgtd. Avg. Remaining Life	Aggregate Intrinsic Value (000's)
Outstanding at beginning of year	2,550,464	$9.42		
Granted	638,486	6.94		
Expired/cancelled/forfeited	(11,460)	15.86		
Exercised	(25,000)	2.60		
Outstanding at end of year	3,152,490	8.95	6.6 years	$2,879
Options exercisable at end of year	2,026,323	$7.90	5.3 years	$2,825
Options expected to vest	1,069,859	10.83	9.0 years	$51

The intrinsic value of options exercised during 2008 and 2007 totaled approximately $9 million and $3.5 million, respectively. The intrinsic value of options exercised during 2009 was immaterial.

The following table summarizes information regarding stock options outstanding at December 31, 2009:

Range of Exercise Price	Options Outstanding 12/31/09	Wgtd. Avg. Remaining Contractual Life	Wgtd. Avg. Exercise Price	Options Exercisable 12/31/09	Wgtd. Avg. Exercise Price
$1.53 - $3.20	638,667	3.4 years	$2.84	638,667	$2.84
$3.21 - $10.00	1,032,384	7.9 years	$5.99	385,898	$4.42
$10.01 - $15.00	968,824	6.7 years	$11.56	827,057	$11.40
$15.01 - $22.40	512,615	8.1 years	$17.57	174,701	$17.54
	3,152,490	6.6 years	$8.95	2,026,323	$7.90

Restricted Stock

The Company computes the fair value of its service based restricted stock using the closing price of the Company's stock at the date of grant, and compensation expense is recognized assuming a 5% estimated forfeiture rate. Restricted stock grants vest over a five year period with one-fourth vesting on each of the first, second, third and fifth anniversaries of the date of the grant. No portion of the restricted stock vests on the fourth anniversary of the date of the grant. Upon a change in control of the Company, all outstanding shares of restricted stock will become immediately vested. Compensation expense related to restricted stock is recognized over the vesting period using the accelerated expense attribution method. Periodically, the Company adjusts compensation expense based on the difference between actual and estimated forfeitures.

The following table details restricted stock activity during 2009:

	Number of Shares	Wgtd. Avg. Fair Value per Share
Outstanding at beginning of year	1,101,608	$12.76
Granted	854,427	3.44
Expired/cancelled/forfeited	(70,695)	9.81
Lapse of restrictions	(439,073)	12.13
Outstanding at December 31, 2009 (1)	1,446,267	$7.58

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(1) At December 31, 2009, the weighted average remaining life of restricted stock outstanding was 3.5 years and the intrinsic value of restricted stock outstanding, using the closing stock price on December 31, 2009, was $8.9 million.

Note 6 – Asset Retirement Obligations

The Company accounts for asset retirement obligations in accordance with ASC Topic 410-20 (SFAS 143, "Accounting for Asset Retirement Obligations"), which requires recording the fair value of an asset retirement obligation associated with tangible long-lived assets in the period incurred. Asset retirement obligations associated with long-lived assets included within the scope of ASC Topic 410-20 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract or by legal construction under the doctrine of promissory estoppel. The Company has legal obligations to plug, abandon and dismantle existing wells and facilities that it has acquired and constructed.

The following table describes all changes to the Company's asset retirement obligation liability (in thousands):

	Years Ended December 31,	
	2009	2008
Asset retirement obligation, beginning of period	$ 25,633	$ 17,451
Liabilities incurred	58	9,464
Liabilities settled	(1,803)	(20,876)
Accretion expense	2,452	1,317
Revisions in estimates	(2,424)	18,277
Asset retirement obligation, end of period	23,916	25,633
Less: current portion of asset retirement obligation	(4,517)	(8,590)
Long-term asset retirement obligation	$ 19,399	$ 17,043

The costs of oilfield related services and materials have declined since December 31, 2008 as a result of the decline in commodity prices and the associated decline in the demand for these services. During 2009, the Company recorded a $2.4 million downward revision to its asset retirement obligation to reflect the estimated decline in abandonment costs since December 31, 2008.

Note 7 – Derivatives

The Company seeks to reduce its exposure to commodity price volatility by hedging a portion of its production through commodity derivative instruments. The Company accounts for commodity derivatives in accordance with ASC Topic 815 (SFAS 133, "Accounting for Derivative Instruments and Hedging Activities", as amended). When the conditions for hedge accounting specified in ASC Topic 815 are met, the Company may designate its commodity derivatives as cash flow hedges. The changes in fair value of derivative instruments that qualify for hedge accounting treatment are recorded in other comprehensive income (loss) until the hedged oil or natural gas quantities are produced. If a hedge becomes ineffective because the hedged production does not occur, or the hedge otherwise does not qualify for hedge accounting treatment, the changes in the fair value of the derivative would be recorded in the income statement as derivative income or expense. At December 31, 2009, the Company's outstanding derivative instruments were considered effective cash flow hedges.

Oil and gas sales include additions (reductions) related to the settlement of gas hedges of $74,333,000, ($6,160,000) and $10,713,000 and oil hedges of $5,559,000, ($2,124,000) and ($791,000) for the years ended December 31, 2009, 2008 and 2007, respectively.

As of December 31, 2009, the Company had entered into the following gas contracts accounted for as cash flow hedges:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
2010	Costless Collar	30,000 Mmbtu	$5.83 - 6.54

At December 31, 2009, the Company had an asset of $2.8 million related to the estimated fair value of these derivative instruments. Based on estimated future commodity prices as of December 31, 2009, the Company would realize a $1.8 million gain, net of taxes, as an increase to gas sales during the next 12 months. These gains are expected to be reclassified based on the schedule of gas volumes stipulated in the derivative contracts.

All of the Company's derivative instruments at December 31, 2009, 2008 and 2007 were designated as hedging instruments under ASC Topic 815. The following tables reflect the fair value of the Company's derivative instruments in the consolidated financial statements as of and for the years ended 2009, 2008 and 2007 (in thousands):

Effect of Derivative Instruments on the Consolidated Balance Sheet at December 31, 2009:

	Asset Derivatives	
Instrument	Balance Sheet Location	Fair Value
Commodity Derivatives	Hedging asset	$ 2,796

Effect of Derivative Instruments on the Consolidated Balance Sheet at December 31, 2008:

	Asset Derivatives	
Instrument	Balance Sheet Location	Fair Value
Commodity Derivatives	Hedging asset	$ 40,571

Effect of Derivative Instruments on the Consolidated Statement of Operations for the twelve months ended December 31, 2009:

Instrument	Amount of Loss Recognized in Other Comprehensive Loss	Location of Gain Reclassified into Income	Amount of Gain Reclassified into Income
Commodity Derivatives	$ (23,792)	Oil and gas sales	$ 79,892

Effect of Derivative Instruments on the Consolidated Statement of Operations for the twelve months ended December 31, 2008:

Instrument	Amount of Gain Recognized in Other Comprehensive Income	Location of Loss Reclassified into Income	Amount of Loss Reclassified into Income
Commodity Derivatives	$ 25,995	Oil and gas sales	$ (8,284)

Effect of Derivative Instruments on the Consolidated Statement of Operations for the twelve months ended December 31, 2007:

Instrument	Amount of Loss Recognized in Other Comprehensive Loss	Location of Gain Reclassified into Income	Amount of Gain Reclassified into Income
Commodity Derivatives	$ (7,067)	Oil and gas sales	$ 9,922

As defined in ASC Topic 820 (SFAS No. 157 "Fair Value Measurements"), fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. ASC Topic 820 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. As presented in the tables below, this hierarchy consists of three broad levels:

- Level 1: valuations consist of unadjusted quoted prices in active markets for identical assets and liabilities and has the highest priority;
- Level 2: valuations rely on quoted prices in markets that are not active or observable inputs over the full term of the asset or liability;
- Level 3: valuations are based on prices or third party or internal valuation models that require inputs that are significant to the fair value measurement and are less observable and thus have the lowest priority.

With the adoption of ASC Topic 820, the Company classified its commodity derivatives based upon the data used to determine fair value. The Company's derivative instruments at December 31, 2009 were in the form of costless collars based on NYMEX pricing. The fair value of these derivatives is derived using an independent third-party's valuation model that utilizes market-corroborated inputs that are observable over the term of the derivative contract. The Company's fair value calculations also incorporate an estimate of the counterparties' default risk for derivative assets and an estimate of the Company's default risk for derivative liabilities. As a result, the Company designates its commodity derivatives as Level 2 in the fair value hierarchy.

The following table summarizes the valuation of the Company's derivatives subject to fair value measurement on a recurring basis as of December 31, 2009 and 2008 (in thousands):

	Fair Value Measurements Using		
Instrument	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity Derivatives - 2009	-	$ 2,796	-
Commodity Derivatives - 2008	-	$ 40,571	-

Note 8 – Long-Term Debt

During 2005, the Company and PetroQuest Energy, L.L.C. issued $150 million in principal amount of 10 3/8% Senior Notes due 2012 (the "Notes"). The Notes are guaranteed by the significant subsidiaries of the Company and PetroQuest Energy L.L.C. The aggregate assets and revenues of the subsidiaries not guaranteeing the Notes consisted of less than 1% of the Company's consolidated assets and revenues at and for the years ended December 31, 2009, 2008 and 2007. At December 31, 2009, the estimated fair value of the Notes was $150 million, based upon a market quote provided by an independent broker. The Notes have numerous covenants including restrictions on liens, incurrence of indebtedness, asset sales, dividend payments and other restricted payments. Interest is payable semi-annually on May 15 and November 15. At December 31, 2009, $1.9 million had been accrued in connection with the May 15, 2010 interest payment and the Company was in compliance with all of the covenants contained in the Notes.

On October 2, 2008, the Company and PetroQuest Energy, L.L.C. (the "Borrower") entered into the Credit Agreement (as amended, the "Credit Agreement") with JPMorgan Chase Bank, N.A., Calyon New York Branch, Bank of America, N.A., Wells Fargo Bank, N.A., and Whitney National Bank. The Credit Agreement provides the Company with a $300 million revolving credit facility that permits borrowings based on the available borrowing base as determined in accordance with the Credit Agreement. The Credit Agreement also allows the Company to use up to $25 million of the borrowing base for letters of credit. The Credit Agreement matures on February 10, 2012; provided, however, if on or prior to such date the Company prepays or refinances, subject to certain conditions, the Notes, the maturity date will be extended to October 2, 2013. As of December 31, 2009 the Company had $29 million of borrowings outstanding under (and no letters of credit issued pursuant to) the Credit Agreement.

The borrowing base under the Credit Agreement is based upon the valuation of the reserves attributable to the Company's oil and gas properties as of January 1 and July 1 of each year. The current borrowing base, which was based upon the valuation of the reserves attributable to the Company's oil and gas properties as of July 1, 2009, is $100 million. The next borrowing base redetermination is scheduled to occur by March 31, 2010. The Company or the lenders may request two additional borrowing base redeterminations each year. Each time the borrowing base is to be re-determined, the administrative agent under the Credit Agreement will propose a new borrowing base as it deems appropriate in its sole discretion, which must be approved by all lenders if the borrowing base is to be increased, or by lenders holding two-thirds of the amounts outstanding under the Credit Agreement if the borrowing base remains the same or is reduced.

The indenture governing the Notes also limits the Company's ability to incur indebtedness under the Credit Agreement. Under the indenture, the Company will not be able to incur additional secured indebtedness under the Credit Agreement if at the time of such incurrence, the total amount of indebtedness under the Credit Agreement is in excess of the greater of (i) $75 million and (ii) 20% of its ACTNA (as defined in the indenture). That calculation is based primarily on the valuation of the Company's estimated reserves of oil and natural gas using the 12-month average commodity prices. Based on the $29 million of borrowings outstanding under the Credit Agreement at December 31, 2009, the indenture would limit the Company's additional borrowings under the Credit Agreement to approximately $46 million.

The Credit Agreement is secured by a first priority lien on substantially all of the assets of the Company and its subsidiaries, including a lien on all equipment and at least 85% of the aggregate total value of the Company's oil and gas properties. Outstanding balances under the Credit Agreement bear interest at the alternate base rate ("ABR") plus a margin (based on a sliding scale of 1.625% to 2.625% depending on borrowing base usage) or the adjusted LIBO rate ("Eurodollar") plus a margin (based on a sliding scale of 2.5% to 3.5% depending on borrowing base usage). The alternate base rate is equal to the highest of (i) the JPMorgan Chase prime rate, (ii) the Federal Funds Effective Rate plus 0.5% or (iii) the adjusted LIBO rate plus 1%. For the purposes of the definition of alternative base rate only, the adjusted LIBO rate is equal to the rate at which dollar deposits of $5,000,000 with a one month maturity are offered by the principal London office of JPMorgan Chase Bank, N.A. in immediately available funds in the London interbank market. For all other purposes, the adjusted LIBO rate is equal to the rate at which Eurodollar deposits in the London interbank market for one, two, three or six months (as selected by the Company) are quoted, as adjusted for statutory reserve requirements for Eurocurrency liabilities. Outstanding letters of credit are charged a participation fee at a per annum rate equal to the margin applicable to Eurodollar loans, a fronting fee and customary administrative fees. In addition, the Company pays commitment fees of 0.5%.

The Company and its subsidiaries are subject to certain restrictive financial covenants under the Credit Agreement, including a maximum ratio of total debt to EBITDAX, determined on a rolling four quarter basis, of 3.0 to 1.0 and a minimum ratio of consolidated current assets to consolidated current liabilities of 1.0 to 1.0, all as defined in the Credit Agreement. The Credit Agreement also includes customary restrictions with respect to debt, liens, dividends, distributions and redemptions, investments, loans and advances, nature of business, international operations and foreign subsidiaries, leases, sale or discount of receivables, mergers or consolidations, sales of properties, transactions with affiliates, negative pledge agreements, gas imbalances and swap agreements. As of December 31, 2009, the Company was in compliance with all of the covenants contained in the Credit Agreement.

Note 9 - Related Party Transactions

Three of the Company's officers, Charles T. Goodson, Stephen H. Green and Mark K. Stover, or their affiliates, are working interest owners and overriding royalty interest owners and E. Wayne Nordberg and William W. Rucks, IV, two of the Company's directors, are working interest owners in certain properties operated by the Company or in which the Company also holds a working interest. As working interest owners, they are required to pay their proportionate share of all costs and are entitled to receive their proportionate share of revenues in the normal course of business. As overriding royalty interest owners they are entitled to receive their proportionate share of revenues in the normal course of business.

During 2009, in their capacities as working interest owners or overriding royalty interest owners, revenues, net of costs, were disbursed to Messrs. Goodson, Green, Stover, Nordberg or their affiliates, in the amounts of $218,000, $559,000, $64,000, $7,000 and with respect to Mr. Rucks, costs in the amount of $43,000 were billed with no revenue disbursed. During 2008, in their capacities as working interest owners or overriding royalty interest owners, revenues, net of costs, were disbursed to Messrs. Goodson, Green, Stover and Nordberg, or their affiliates, in the amounts of $2,876,000, $1,206,000, $249,000 and $4,000, respectively. During the year ended December 31, 2007, in their capacities as working interest owners or overriding royalty interest owners, revenues, net of costs, were disbursed to Messrs. Goodson, Green and Stover, or their affiliates, in the amounts of $2,519,300, $1,267,100 and $62,200, respectively, and with respect to the working interests of Mr. Nordberg, revenues exceeded costs by $3,700. With respect to Mr. Goodson, gross revenues attributable to interests, properties or participation rights held by him prior to joining the Company as an officer and director on September 1, 1998 represent substantially all of the gross revenue received by him in 2009.

In its capacity as operator, the Company incurs drilling and operating costs that are billed to its partners based on their respective working interests. At December 31, 2009, the Company's joint interest billing receivable included approximately $225,000 from the related parties discussed above or their affiliates, attributable to their share of costs. This represents less than 2% of the Company's total joint interest billing receivable at December 31, 2009.

Periodically, the Company charters private aircraft for business purposes. During 2009, 2008 and 2007, the Company paid approximately $13,500, $6,700 and $170,000, respectively, to a third party operator in connection with the Company's use of flight hours owned by Charles T. Goodson through a fractional ownership arrangement with the third party operator. These amounts represent the cost of the hours purchased by Mr. Goodson. The Company's use of flight hours purchased by Mr. Goodson was pre-approved by the Company's Audit Committee and there is no agreement or obligation by or on behalf of the Company to utilize this or any other aircraft arrangement.

Note 10 – Ceiling Test

The Company uses the full cost method to account for its oil and natural gas operations. Accordingly, the costs to acquire, explore for and develop oil and natural gas properties are capitalized. Capitalized costs of oil and gas properties, net of accumulated DD&A and related deferred taxes, are limited to the estimated future net cash flows from proved oil and gas reserves, including the effects of cash flow hedges in place, discounted at 10%, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (the full cost ceiling). If capitalized costs exceed the full cost ceiling, the excess is charged to ceiling test write down of oil and gas properties in the quarter in which the excess occurs.

At December 31, 2009, the Company computed the estimated future net cash flows from its proved oil and gas reserves, discounted at 10%, using a historical 12-month average price based on the price of the first day of each respective month, including the effect of hedges in place, of $3.10 per Mcfe and $60.57 per barrel. Due to the low average market prices during the twelve months ended December 31, 2009, capitalized costs exceeded the full cost ceiling, resulting in a $52.6 million non-cash ceiling test write-down of the Company's oil and gas properties during the fourth quarter of 2009. The Company's cash flow hedges in place at December 31, 2009 reduced the fourth quarter ceiling test write-down by approximately $20 million. In total, the Company recorded $156.1 million of ceiling test write-downs during 2009.

Note 11 - Investment in Oil and Gas Properties

The following tables disclose certain financial data relative to the Company's oil and gas producing activities, which are located onshore and offshore the continental United States:

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities
(amounts in thousands)

	For the Year-Ended December 31, 2009	2008	2007
Acquisition costs:			
Proved	$ 427	$ 3,014	$ 1,253
Unproved	1,592	58,826	32,833
Exploration costs:			
Proved	16,495	149,811	104,669
Unproved	3,249	6,048	15,908
Development costs	19,333	118,891	71,973
Capitalized general and administrative and interest costs	18,009	21,181	14,061
Total costs incurred	$ 59,105	$ 357,771	$ 240,697

	For the Year-Ended December 31, 2009	2008	2007
Accumulated depreciation, depletion and amortization (DD&A)			
Balance, beginning of year	$ (832,290)	$ (432,530)	$ (314,869)
Provision for DD&A	(83,613)	(131,348)	(116,384)
Ceiling test writedown	(156,134)	(266,156)	-
Sale of proved properties and other	(10,344)	(2,256)	(1,277)
Balance, end of year	$ (1,082,381)	$ (832,290)	$ (432,530)
DD&A per Mcfe	$ 2.44	$ 3.89	$ 3.70

At December 31, 2009 and 2008, unevaluated oil and gas properties totaled $108,079,000 and $119,847,000, respectively, and were not subject to depletion. Unevaluated costs at December 31, 2009 included $3,249,000 of costs related to 37 exploratory wells in progress at year-end. These costs will be transferred to evaluated oil and gas properties during 2010 upon the completion of drilling. At December 31, 2008, unevaluated costs included $6,048,000 related to exploratory wells in progress. All of these costs were transferred to evaluated oil and gas properties during 2009. The Company capitalized $8,679,000, $10,525,000 and $6,539,000 of interest during 2009, 2008 and 2007, respectively. Of the total unevaluated oil and gas property costs at December 31, 2009, $12,865,000, or 12%, was incurred in 2009, $71,347,000 was incurred in 2008 and $23,867,000 was incurred in prior years. The Company expects that the majority of the unevaluated costs at December 31, 2009 will be evaluated within the next three years including $21,200,000 that the company expects to be evaluated during 2010.

Note 12 - Income Taxes

The Company follows the provisions of ASC Topic 740 (SFAS No. 109, "Accounting For Income Taxes,") which provides for recognition of deferred tax assets and liabilities for deductible temporary timing differences, operating loss carryforwards, statutory depletion carryforwards and tax credit carryforwards net of a valuation allowance for any asset for which it is more likely than not will not be realized in the Company's tax return. As a result of the ceiling test write-downs realized during 2009 and 2008, the Company has incurred a cumulative three-year loss. Because of the impact the cumulative loss has on the determination of the recoverability of deferred tax assets through future earnings, the Company assessed the realizability of its deferred tax asset based on the future reversals of existing deferred tax liabilities. Accordingly, the Company established a valuation allowance of $24.6 million at December 31, 2009 for a portion of the deferred tax asset. The impact of the change in valuation allowance is included in the Company's effective tax rate for 2009 and changes to the valuation allowance in future periods will impact the effective tax rate for such periods.

An analysis of the Company's deferred taxes follows (amounts in thousands):

	December 31, 2009	December 31, 2008
Net operating loss carryforwards	$ 8,031	$ 13,301
Percentage depletion carryforward	3,344	2,619
Alternative minimum tax credit	201	144
Contributions carryforward and other	65	156
Temporary differences:		
Oil and gas properties - full cost	13,859	(30,207)
Hedges	(1,040)	(15,011)
Compensation expense	153	153
Valuation allowance	(24,613)	-
Deferred tax liability	$ -	$ (28,845)

At December 31, 2009, the Company had approximately $29,000,000 of operating loss carryforwards. If not utilized, approximately $2,711,000 of such carryforwards would expire in 2010 and the remainder would completely expire by the year 2029. The Company has available for tax reporting purposes $9,554,000 in statutory depletion deductions that may be carried forward indefinitely.

Income tax expense (benefit) for each of the years ended December 31, 2009, 2008 and 2007 was different than the amount computed using the Federal statutory rate (35%) for the following reasons (amounts in thousands):

	For the Year-Ended December 31, 2009	2008	2007
Amount computed using the statutory rate	$ (36,689)	$ (53,389)	$ 22,499
Increase (reduction) in taxes resulting from:			
State & local taxes	(2,306)	(3,357)	1,414
Percentage depletion carryforward	(725)	310	(860)
Non-deductible stock option expense (1)	311	490	462
Other	161	365	149
Change in valuation allowance	24,613	-	-
Income tax expense (benefit)	$ (14,635)	$ (55,581)	$ 23,664

(1) Relates to compensation expense recognized on the vesting of Incentive Stock Options

Note 13 - Commitments and Contingencies

The Company is a party to ongoing litigation in the normal course of business. See Note 14 for a discussion of recently settled litigation. While the outcome of lawsuits or other proceedings against the Company cannot be predicted with certainty, management believes that the effect on its financial condition, results of operations and cash flows, if any, will not be material.

A portion of the production that the Company operates in Oklahoma is committed to a firm transportation agreement. Under the terms of the agreement, the Company must deliver 9.1 Bcf of natural gas per year through October 31, 2013.

Lease Commitments

The Company has operating leases for office space and equipment, which expire on various dates through 2013.

Future minimum lease commitments as of December 31, 2009 under these operating leases are as follows (in thousands):

2010	$ 1,087
2011	894
2012	749
2013	63
2014	-
Thereafter	-
	$ 2,793

Total rent expense under operating leases was approximately $1,082,000, $965,000 and $910,000 in 2009, 2008 and 2007, respectively.

Note 14 – Subsequent Events

In January 2010, the Company received a $9 million cash settlement related to a lawsuit filed in 2008 relating to disputed interests in certain oil and gas assets purchased in 2007. In addition to the cash received, effective January 1, 2010, the Company will receive additional interests in wells that are currently producing, including additional interests in wells in which the Company has an existing interest. The Company expects to recognize the effects of this settlement in 2010.

As of February 26, 2010, which is the date these financial statements were issued, the Company completed its review and analysis of potential subsequent events and believes it has disclosed the applicable items accordingly.

Note 15 - Oil and Gas Reserve Information - Unaudited

The Company's net proved oil and gas reserves at December 31, 2009 have been estimated by independent petroleum engineers in accordance with guidelines established by the Securities and Exchange Commission.

The estimates of proved oil and gas reserves constitute those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. However, there are numerous uncertainties inherent in estimating quantities of proved reserves and in providing the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. In addition, the present values should not be construed as the current market value of the Company's oil and gas properties or the cost that would be incurred to obtain equivalent reserves.

On December 29, 2008, the SEC issued a revision to Staff Accounting Bulletin 113 ("SAB 113") which established guidelines related to modernizing accounting and disclosure requirements for oil and natural gas companies. The revised disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. The revised rules also allow companies the option to disclose probable and possible reserves in addition to the existing requirement to disclose proved reserves. The revised disclosure requirements also require companies to report the independence and qualifications of third party preparers of reserves and file reports when a third party is relied upon to prepare reserves estimates. A significant change to the rules involves the pricing at which reserves are measured. The revised rules utilize a historical 12-month average price based on beginning of the month pricing during the 12-month period prior to the ending date of the balance sheet to report oil and natural gas reserves rather than year-end prices. In addition, the 12-month average will also be used to measure ceiling test impairments and to compute depreciation, depletion and amortization. The revised rules are effective for reserves estimated at December 31, 2009 with first reporting for calendar year companies in their 2009 annual reports. The change in reserve estimation methodology resulted in a 23.3 Bcfe decrease to the Company's total proved reserves and a $170.2 million reduction in the standardized measure.

During 2009, the Company's estimated proved reserves declined by 3%. This decrease was primarily due to the impact of the change in pricing methodology from the revised SEC guidelines. Partially offsetting this decline was an increase in reserves attributable to positive performance revisions and extensions and discoveries from the Company's Oklahoma assets. In total, the Company added approximately 43 Bcfe of proved reserves in Oklahoma during 2009. Overall, the Company had a 98% drilling success rate during 2009 on 82 gross wells drilled.

The following table sets forth an analysis of the Company's estimated quantities of net proved and proved developed oil (including condensate) and gas reserves, all located onshore and offshore the continental United States:

	Oil in MBbls	Natural Gas and NGL in MMcfe
Proved reserves as of December 31, 2006	2,731	118,153
Revisions of previous estimates	109	14,047
Extensions, discoveries and other additions	366	37,590
Purchase of producing properties	234	173
Sale of producing properties	(18)	(2,529)
Production	(1,080)	(24,966)
Proved reserves as of December 31, 2007	2,342	142,468
Revisions of previous estimates	(21)	(11,126)
Extensions, discoveries and other additions	499	69,800
Purchase of producing properties	62	1,047
Sale of producing properties	-	(295)
Production	(681)	(29,708)
Proved reserves as of December 31, 2008	2,201	172,186
Revisions of previous estimates	321	(10,617)
Extensions, discoveries and other additions	9	39,303
Purchase of producing properties	-	-
Sale of producing properties	-	(2,913)
Production	(600)	(30,598)
Proved reserves as of December 31, 2009	1,931	167,361
Proved developed reserves		
As of December 31, 2007	2,070	95,639
As of December 31, 2008	2,030	124,020
As of December 31, 2009	1,775	100,430

The following tables (amounts in thousands) present the standardized measure of future net cash flows related to proved oil and gas reserves together with changes therein, as defined by the FASB. Future production and development costs are based on current costs with no escalations. Estimated future cash flows have been discounted to their present values based on a 10% annual discount rate.

Standardized Measure	December 31, 2009	December 31, 2008	December 31, 2007
Future cash flows	$ 614,293	$ 889,732	$ 1,155,236
Future production costs	(193,427)	(275,117)	(240,849)
Future development costs	(148,595)	(148,167)	(134,993)
Future income taxes	(3,166)	(14,479)	(143,683)
Future net cash flows	269,105	451,969	635,711
10% annual discount	(94,817)	(137,182)	(188,453)
Standardized measure of discounted future net cash flows	$ 174,288	$ 314,787	$ 447,258

Changes in Standardized Measure	Year Ended December 31, 2009	Year Ended December 31, 2008	Year Ended December 31, 2007
Standarized measure at beginning of year	$ 314,787	$ 447,258	$ 332,833
Sales and transfers of oil and gas produced, net of production costs	(95,555)	(259,950)	(206,477)
Changes in price, net of future production costs	(100,150)	(172,214)	153,961
Extensions and discoveries, net of future production and development costs	2,790	147,089	95,850
Changes in estimated future development costs, net of development costs incurred during this period	38,407	36,567	12,014
Revisions of quantity estimates	(15,045)	(25,037)	66,025
Accretion of discount	32,719	54,065	38,431
Net change in income taxes	9,698	80,988	(41,913)
Purchase of reserves in place	-	1,944	14,108
Sale of reserves in place	(2,138)	(1,378)	(9,293)
Changes in production rates (timing) and other	(11,225)	5,455	(8,281)
Standardized measure at end of year	$ 174,288	$ 314,787	$ 447,258

The weighted average prices of oil and gas used for the above tables at December 31, 2009, 2008 and 2007 were $60.57, $41.53 and $96.83 per barrel, respectively, and $2.97, $4.64 and $6.52 per Mcfe, respectively.

Note 16 – Summarized Quarterly Financial Information – Unaudited

Summarized quarterly financial information is as follows (amounts in thousands except per share data):

	Quarter Ended			
	March 31	June 30	September 30	December 31
2009:				
Revenues	$ 59,449	$ 55,261	$ 50,254	$ 53,911
Income (loss) from operations (1)	(100,476)	17,184	13,616	(35,149)
Net income (loss) available to common stockholders (1)	(66,957)	7,746	4,453	(40,572)
Earnings (loss) per share:				
Basic (3)	$ (1.36)	$ 0.15	$ 0.07	$ (0.66)
Diluted (3)	$ (1.36)	$ 0.15	$ 0.07	$ (0.66)
2008:				
Revenues	$ 76,550	$ 92,868	$ 78,275	$ 66,265
Income (loss) from operations (2)	24,719	36,793	28,847	(242,900)
Net income (loss) available to common stockholders (2)	14,161	21,775	16,758	(154,794)
Earnings (loss) per share:				
Basic (3)	$ 0.28	$ 0.43	$ 0.33	$ (3.14)
Diluted (3)	$ 0.25	$ 0.41	$ 0.32	$ (3.14)

(1) Loss from operations and net loss available to common stockholders reported during the three months ended March 31 and December 31, 2009 include non-cash ceiling test write-downs of $103.5 million and $52.6 million, respectively (see Note 10).

(2) Income from operations and net income available to common stockholders reported during the three months ended September 30, 2008 include a gain on the sale of gas gathering systems totaling $26.8 million (see Note 1). Loss from operations and net loss available to common stockholders reported during the three months ended December 31, 2008 include a non-cash ceiling test write-down of $246.8 million.

(3) Effective January 1, 2009, the Company adopted the provisions of ASC Topic 260-10-45 (FSP No. EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities"). As a result of adoption, the Company's earnings per share for 2009 have been calculated in accordance with ASC Topic 260-10-45 and the Company retrospectively adjusted the calculation of earnings per share for 2008.

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statements (Form S-3 Nos. 333-158446, 333-124746, 333-42520 and 333-89961 and Form S-8 Nos. 333-151296, 333-134161, 333-102758, 333-88846, 333-67578, 333-52700 and 333-65401) of PetroQuest Energy, Inc. and in the related Prospectuses of our reports dated February 26, 2010, with respect to the consolidated financial statements of PetroQuest Energy, Inc. and the effectiveness of internal control over financial reporting of PetroQuest Energy, Inc., included in this Annual Report (Form 10-K) for the year ended December 31, 2009.

/s/Ernst & Young LLP
New Orleans, Louisiana
February 26, 2010

Exhibit 23.2

Consent Of Ryder Scott Company, L.P.

We hereby consent to (i) the inclusion of our reserve report relating to certain estimated quantities of the proved reserves of oil and gas, future net income and discounted future net income, effective December 31, 2009 of PetroQuest Energy, Inc. (the "Company") in this Annual Report on Form 10-K prepared by the Company for the year ending December 31, 2009, filed as Exhibit 99.1 of the Form 10-K, and (ii) the incorporation by reference in this Annual Report on Form 10-K prepared by the Company for the year ending December 31, 2009, and to the incorporation by reference thereof into the Company's previously filed Registration Statements on Form S-3 (File Nos. 333-158446, 333-124746, 333-42520 and 333-89961) and Form S-8 (File Nos. 333-151296, 333-134161, 333-102758, 333-88846, 333-67578, 333-52700 and 333-65401), of information contained in our report relating to certain estimated quantities of the Company's proved reserves of oil and gas, future net income and discounted future net income, effective December 31, 2009. We further consent to references to our firm under the headings "RISK FACTORS" and "Oil and Gas Reserves," included in or made a part of the Annual Report on Form 10-K prepared by the Company for the year ended December 31, 2009

We further wish to advise that we are not employed on a contingent basis and that at the time of the preparation of our report, as well as at present, neither Ryder Scott Company, L.P. nor any of its employees had, or now has, a substantial interest in PetroQuest Energy, Inc. or any of its subsidiaries, as a holder of its securities, promoter, underwriter, voting trustee, director, officer or employee.

/s/ Ryder Scott Company, L.P.
RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580
Houston, Texas
February 24, 2010

Exhibit 23.3

Consent Of Netherland, Sewell and Associates, Inc.

We hereby consent to (i) the inclusion of our reserve report relating to certain estimated quantities of the proved reserves of oil and gas, future net income and discounted future net income, effective December 31, 2009 of PetroQuest Energy, Inc. (the "Company") in this Annual Report on Form 10-K prepared by the Company for the year ending December 31, 2009, filed as Exhibit 99.2 of the Form 10-K, and (ii) the incorporation by reference in this Annual Report on Form 10-K prepared by the Company for the year ending December 31, 2009, and to the incorporation by reference thereof into the Company's previously filed Registration Statements on Form S-3 (File Nos. 333-158446, 333-124746, 333-42520 and 333-89961) and Form S-8 (File Nos. 333-151296, 333-134161, 333-102758, 333-88846, 333-67578, 333-52700 and 333-65401), of information contained in our report relating to certain estimated quantities of the Company's proved reserves of oil and gas, future net income and discounted future net income, effective December 31, 2009. We further consent to references to our firm included in or made a part of the Annual Report on Form 10-K prepared by the Company for the year ended December 31, 2009

We further wish to advise that we are not employed on a contingent basis and that at the time of the preparation of our report, as well as at present, neither Netherland, Sewell and Associates, Inc. nor any of its employees had, or now has, a substantial interest in PetroQuest Energy, Inc. or any of its subsidiaries, as a holder of its securities, promoter, underwriter, voting trustee, director, officer or employee.

NETHERLAND, SEWELL AND ASSOCIATES, INC.
By: /s/ C.H. (Scott) Rees III, P.E.
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer
Dallas, Texas
February 26, 2010

Exhibit 31.1

I, Charles T. Goodson, certify that:

1. I have reviewed this Form 10-K of PetroQuest Energy, Inc.;

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(s) 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(s) 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.

/s/ Charles T. Goodson
Charles T. Goodson
Chief Executive Officer
February 26, 2010

Exhibit 31.2

I, J. Bond Clement, certify that:

6. I have reviewed this Form 10-K of PetroQuest Energy, Inc.;

7. 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;

8. 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;

9. The registrant's other certifying officer(s) 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

10. The registrant's other certifying officer(s) 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.

__/s/ J. Bond Clement__
J. Bond Clement
Chief Financial Officer
February 26, 2010

Exhibit 32.1

Certification 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 PetroQuest Energy, Inc. (the "Company") on Form 10-K for the year ending December 31, 2009 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Charles T. Goodson, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §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, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/Charles T. Goodson
Charles T. Goodson
Chief Executive Officer
February 26, 2010

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

Certification 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 PetroQuest Energy, Inc. (the "Company") on Form 10-K for the year ending December 31, 2009 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, J. Bond Clement, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §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, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ J. Bond Clement
J. Bond Clement
Chief Financial Officer
February 26, 2010

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

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BOARD OF DIRECTORS

Charles T. Goodson
Chairman of the Board,
Chief Executive Officer, and President
PetroQuest Energy, Inc.

W.J. Gordon III *#^
Vice President of Strategic Planning
Franciscan Missionaries of Our Lady Health System

Michael L. Finch *#^
Private Investments

Charles F. Mitchell II, M.D. *#^
Physician, Private Investments

E. Wayne Nordberg *#^
Hollow Brook Associates, LLC

William W. Rucks, IV *#^
Private Investments

*Member of the Compensation Committee
#Member of the Audit Committee
^Member of the Nominating and Corporate Governance Committee

SENIOR MANAGEMENT

Charles T. Goodson
Chairman of the Board,
Chief Executive Officer, and President

Daniel G. Fournerat
Executive Vice President, General Counsel,
Chief Administrative Officer, and Secretary

W. Todd Zehnder
Executive Vice President
Chief Operating Officer

J. Bond Clement
Executive Vice President
Chief Financial Officer, and Treasurer

Art M. Mixon
Executive Vice President
Operations and Production

Mark K. Stover
Executive Vice President
Exploration and Development

Stephen H. Green
Senior Vice President
Exploration

Dalton F. Smith III
Senior Vice President
Business Development

James S. Blair
Vice President
Business Development

CORPORATE ADDRESS

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400 East Kaliste Saloom Road, Suite 6000
Lafayette, Louisiana 70508
Telephone: (337) 232-7028
Fax: (337) 232-0044
Web: www.petroquest.com

EXPLORATION OFFICES

450 Gears Road, Suite 330
Houston, Texas 77067
Telephone: (713) 784-8300
Fax: (713) 784-8327

1717 S. Boulder, Suite 201
Tulsa, Oklahoma 74119
Telephone: (918) 582-2770
Fax: (918) 582-2778

TRANSFER AGENT AND REGISTRAR

American Stock Transfer & Trust Company
59 Maiden Lane
New York, New York 10038
Telephone: (718) 921-8145

INDEPENDENT AUDITORS

Ernst & Young LLP
New Orleans, Louisiana 70170

LEGAL COUNSEL

Porter & Hedges, LLP
Houston, Texas 77002

Onebane Law Firm
Lafayette, Louisiana 70502

ANNUAL MEETING

The Company's Annual Meeting of Stockholders will be held at 9:00 A.M. CDT on May 12, 2010, at the City Club at River Ranch at 221 Elysian Fields Dr., Lafayette, LA. 70508.

FORM 10-K

Copies of the Company's Annual Report on Form 10-K may be obtained, without charge, by writing to our Corporate Secretary at our Corporate Address or on the Company's website at www.petroquest.com.

COMMON STOCK LISTING

Listed on NYSE as PQ

PQ
LISTED
NYSE

PetroQuest Energy, Inc.

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