PetroQuest Energy, Inc.

2007 **ANNUAL** report

the CONTINUATION of *Growth*

Corporate Profile

GROWTH Delivered

In 2007, PetroQuest Energy continued adding value as we posted record results for shareholders for the fourth consecutive year. This past year PetroQuest increased revenues by 31%, net cash flow from operations 87%, reserves by 16% and production by 22%. More than 170% of our 2007 production was replaced through our capital investment program. We will continue to invest in our core operating areas with the goal of building upon our past success.

RESULTS Achieved

Growth was achieved through an established strategy of balancing exploration, development and acquisitions. Important elements of this program were the preservation of stable cash flow from successful drilling and effective management of operating costs. Steady cash flow is enhanced by PetroQuest's operatorship of approximately 70% of its daily production from more than 675 wells.

PROMISES of Success Fulfilled

Consistent with our long-range strategies, PetroQuest successfully executed its commitment to a more aggressive drilling program, with 87 wells drilled in 2007, 87% completed as successful. We plan to drill 140 to 150 wells in 2008. Another long-range commitment, to maintain a strong balance sheet, was realized during the year with the successful capital infusion of $71 million via our 6.875% cumulative convertible perpetual preferred stock offering. The stock price of PetroQuest on December 31, 2007 was $14.30, an improvement of 12% during the year versus 5.49% realized by the S&P 500.

OUTLOOK Defined

We estimate our 2008 capital investment program will be $200 million to $220 million, with 73% allocated to the Company's long-lived basins in Oklahoma, Arkansas and East Texas and 27% invested in the Gulf Coast basin. Geographic concentration of desirable acreage and seismic coverage support our ongoing successful drilling programs in each of our core operating areas. For 2008, we forecast our daily production will average between 94 MMcfe and 100 MMcfe.

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Notice of Annual Meeting of Stockholders

The Company's Annual Meeting of Stockholders will be held at 9:00 a.m. CDT on May 14, 2008, at the City Club at River Ranch at 221 Elysian Fields Drive, Lafayette, Louisiana 70508.

Financial & Operational Highlights

Growth	2002 Annual	2003 Annual	2004 Annual	2005 Annual	2006 Annual	2007 Q1	2007 Q2	2007 Q3	2007 Q4	2007 Annual	5-Year CAGR
Production											
Natural Gas, MMcf	7,765	5,193	9,305	12,058	21,528	5,533	6,104	6,621	6,708	24,966	26%
Crude Oil, MBbl	929	745	818	665	695	360	287	243	190	1,080	3%
Natural Gas, MMcfe	13,340	9,660	14,216	16,051	25,697	7,692	7,824	8,079	7,849	31,444	19%
Financial $000s, except per share amounts											
Total Revenues	$ 48,238	$ 48,688	$ 84,868	$ 124,594	$ 200,544	$ 64,008	$ 66,760	$ 65,500	$ 67,406	$ 263,674	40%
Net Income	2,307	3,640	16,348	21,417	23,986	10,814	9,630	8,038	12,137	40,619	77%
Preferred Stock Dividends	--	--	--	--	--	--	--	74	1,300	1,374	NM
Net Income Available to Common Stockholders	$ 2,307	$ 3,640	$ 16,348	$ 21,417	$ 23,986	$ 10,814	$ 9,630	$ 7,964	$ 10,837	$ 39,245	76%
Per Common Share:											
Basic	$ 0.06	$ 0.08	$ 0.37	$ 0.46	$ 0.50	$ 0.23	$ 0.20	$ 0.16	$ 0.22	$ 0.82	69%
Diluted	$ 0.06	$ 0.08	$ 0.35	$ 0.44	$ 0.49	$ 0.22	$ 0.19	$ 0.16	$ 0.22	$ 0.79	67%

Year-over-Year Review	2002	2003	2004	2005	2006	2007	5-Year CAGR
Reserves							
Natural Gas, MMcf	37,137	57,793	79,069	109,115	118,153	142,468	31%
Crude Oil, MBbl	5,258	4,245	3,714	3,642	2,731	2,342	NM
Natural Gas, MMcfe	68,685	83,263	101,353	130,967	134,539	156,520	18%
Percent Developed	62%	67%	68%	69%	72%	69%	
Percent Natural Gas	54%	69%	78%	83%	88%	91%	
Percent Offshore	84%	55%	59%	39%	30%	29%	
Future Undiscounted Net Cash Flows, $000s	$ 216,934	$ 293,349	$ 443,487	$ 861,689	$ 516,013	$ 779,395	29%
SEC PV-10, Before Taxes, $000s	$ 166,048	$ 214,365	$ 326,267	$ 639,734	$ 384,313	$ 540,651	27%
Commodity Prices							
PetroQuest Realized, Natural Gas, $/Mcf	$ 3.20	$ 5.14	$ 5.99	$ 7.47	$ 7.04	$ 7.21	
Henry Hub Cash Market Average, Natural Gas, $/Mcf	3.32	5.49	6.15	8.89	6.73	6.97	Source: Bloomberg
PetroQuest Realized, Crude Oil, $/Bbl	25.07	28.47	35.31	45.76	60.91	70.52	
WTI (Cushing) Spot Average, Crude Oil, $/Bbl	26.17	31.06	41.48	56.59	66.09	72.23	Source: Bloomberg
PetroQuest Realized, Natural Gas Equivalent, $/Mcfe	3.61	4.96	5.95	7.51	7.54	8.15	
Statistics							
Reserve Replacement, Excluding Revisions, %	211%	384%	220%	337%	152%	132%	
6-Year Reserve Replacement, Excluding Revisions, %						210%	
Finding & Development Costs, Excluding Revisions, $/Mcfe	$ 2.31	$ 1.43	$ 2.77	$ 3.62	$ 4.36	$ 5.82	
6-Year Finding & Development Costs, Excluding Revisions, $/Mcfe						$ 3.50	
Per Unit Analysis, $/Mcfe							
Total Revenues	$ 3.61	$ 4.96	$ 5.97	$ 7.76	$ 7.80	$ 8.39	18%
Lease Operating Expense and Production Taxes	0.79	1.07	1.04	1.54	1.61	1.27	10%
Gas Gathering Costs	--	--	--	0.08	0.14	0.13	NM
Gross Operating Margin	2.82	3.89	4.93	6.14	6.05	6.99	20%
Interest Expense	0.02	0.06	0.20	0.77	0.56	0.42	84%
General and Administrative	0.38	0.46	0.44	0.46	0.59	0.67	12%
Preferred Stock Dividends	--	--	--	--	--	0.04	NM
Gross Cash Margin	$ 2.42	$ 3.37	$ 4.29	$ 4.91	$ 4.90	$ 5.86	19%

Letter to

PetroQuest Energy is an oil & natural gas company with a long track record of delivering GROWTH and very attractive returns for its shareholders.

For 2007 we again reported record revenues, production, cash flows and year-end proved reserves. We completed our most extensive drilling program to date, broadened our exposure to high-potential drilling projects in Oklahoma, East Texas, Arkansas, and in and along the Louisiana coast and the Gulf of Mexico, while generating excellent cash margins and preserving our cost structure. I am very proud of how well our people were able to execute our strategies for the benefit of our stockholders. I want to make an interesting point here: 100% of PetroQuest's staff and directors own stock in the Company. They are intently focused on increasing their wealth through hard-work and dedication to PetroQuest's success. I hope our investors are as pleased with their efforts.

Solid VALUE

With geographic focus on projects which offer us many years of drilling inventory, we are planning our 2008 capital investment with the goal of boosting our daily production base more than 15% and our proved reserves more than 30%. We have posted increases in annual production for four consecutive years. Since 2003, our oil and gas professionals have increased production an average of more than 34% each year. While continuous growth in production and cash flow are traditionally viewed as key points of measurement of a company's valuation, we look to the full cycle value of our properties – 'Are we generating an attractive return on our invested capital?' In 2007, we've generated nearly $7.00 per Mcfe of gross operating margin. This reflects a return of $2.00 per Mcfe for every $1.00 per Mcfe invested for the last six years.

Stockholders

In our industry, the mark of a good business model is a company's ability to generate competitive returns regardless of the vagaries of the commodity markets, field-level expenses or financial markets. We believe good business depends on not over-reacting or over-reaching during volatile times. The day-to-day challenge is managing what is within our control while being prepared to react to the challenges that aren't. Our success has been the result of vigilant monitoring of our day-to-day operations, ensuring that we remain on our long-term track.

Our focus is to protect, enhance and expand our value for our shareholders. Yes, the measured period of time is important. A $100,000 investment made in PetroQuest in 1999 is today worth $1.8 million, a 43% compound annual growth rate. Measuring from the end of 2003, a $100,000 investment in PetroQuest would have returned 65% per year to the investor. Returns, we believe, are the numbers that shareholders focus on most. How will we do in 2008? We see strong opportunities to grow revenues, reserves, cash flow and profits. To realize these expectations, we are forecasting significant capital investment, higher production rates, and will continue our efforts to hold down operating costs. We expect to drill 140 to 150 gross wells from our inventory of drillable locations. We operate more than 58% of our reserves, and our knowledge of our assets is a critical component of our successes.

Outlook

The world is spinning faster. I know it's still a 24-hour day, but we're all doing more in a day than we did 20, 10, even five years ago. Globally, the world is consuming more, not less, energy. Developing countries need more energy. The Energy Information Administration (EIA) projects that total world consumption of marketed energy will increase 57% from 2004 to 2030. Fuel from oil and natural gas is projected to be the largest source of this energy. Natural gas consumption is projected to increase an average of about 2.0% per year, going from 100 Tcf to 163 Tcf per annum by 2030. The EIA believes rising oil prices actually increase the demand for natural gas, given the disconnection between the two fossil fuels on an economic heat-equivalent basis. At year-end 2007, oil traded for $96.00, natural gas for $7.46. On the traditional 6:1 basis, natural gas is cheaper by 114%. As globalization continues, industrial use is projected by the EIA to make up 43% of total natural gas consumption in 2030.

What does this mean for PetroQuest? Our operations are located in areas that are infrastructure-rich with high demand. Our average realized natural gas price is 3% higher than the posted prices at the Henry Hub, America's natural gas benchmark. On the supply side, the average unconventional natural gas well being drilled in America has a decline rate of more than 50%, meaning, each year a well will produce 50% of its remaining reserves until it's determined to have reached its economic limit. In terms of demand, utilities are converting to or building natural gas-fired plants, because they find that coal-fired systems meet too much opposition from government agencies. This conversion supports the longer-term view that natural gas prices will stay strong because utilities need assurances that they have access to this important energy supply to meet their own day-to-day demand for energy from

Our roots run deep in South Louisi

In 2001, the average price for natural gas sold at the Henry Hub was less than $3.00 per million British thermal unit (MMBtu). As I'm writing this letter to you, the average price looking forward for natural gas is more than $9.90 per MMBtu. When you factor in the weak U.S. dollar, which makes our goods and services more attractive to foreign buyers, you can see just how this Lafayette, Louisiana-based company directly benefits from a growing global economy.

Historically, the energy equivalency ratio between natural gas and crude oil is 6:1. In 2005, that ratio was 6.3:1. Today, the ratio is roughly 10.9:1. Natural gas is a cheap source of energy, and as a result, I believe it will remain in high demand through its increased consumption by utilities and industrial end-users.

Europe, the Middle East and Africa do not have the large storage facilities for natural gas as we do here in North America. Therefore, it makes sense, given America's sizeable natural gas resources, access to capital, pipeline infrastructure and proven technological and industrial ingenuity, for the industry to develop an export business for future natural gas production. We'll never be energy independent. If you want true energy independence, producers like PetroQuest must be allowed to drill more, not less, for these resources. America can become a global energy participant, as opposed to our current status as the world's largest energy consumer, if we put our collective shoulders into such enterprises. And if this happens, PetroQuest's asset base is well-positioned to benefit from increased demand and higher natural gas prices.

Results

Our SUCCESS is the Product of Our Experience and Hard Work

This is a good time to bring your attention to our 2007 results. By any measure, 2007 wa a great year for PetroQuest. We generated revenues of $263.7 million, a 31% increase from 2006 Net cash provided by operating activities was $223.7 million, up 87% from 2006. Average productio was 86 MMcfe per day in 2007, an improvement of 22% compared to 2006. For the perio 2003 to 2007, PetroQuest more than tripled its production, realizing a greater than 34% annua average growth rate. Our 2007 net income was $39.2 million, or $0.79 per diluted share. This is th eighth consecutive year PetroQuest reported net income. For 2008, we're forecasting our productio will average between 94 MMcfe and 100 MMcfe per day. Factoring in current commodity price and our capital budget, PetroQuest will extend its consecutive net income for yet another year.

Our REPUTATION is Built from Our Actions

Based on PetroQuest's almost 10 years as a public company, we are excited about our future. We ar well-capitalized, with an asset base that is capable of generating significant amounts of revenue an cash flow. This past year is one where we made significant and lasting inroads towards our strategi vision. With this success comes the opportunity to move smartly along with our growth plans remain prosperous and expand within each of our core operating areas.

There will always be an opportunity to grow when there is an open mind and willing effor It takes courage to explore, to drill. And it takes courage to take a risk, calculated or on hunches An excellent example of how we've benefited from our experience and know-how is in Oklahoma' Arkoma Basin. From a standing start of zero acres in 2003, we now control more than 30,000 acre with about 1,285 drilling locations offering more than 500 Bcfe of reserves net to the compan Capitalizing on the mistakes and gains made by other operators drilling for the Woodford Shal we learned how to drill our wells faster and cheaper, and to find more estimated reserves per wel We based our original engineering models on logs and 2-D seismic. We estimated that we coul drill a Woodford Shale well for about $4.7 million, find about 2.5 Bcfe of natural gas and begi producing at roughly 2.5 MMcfe per day. From applying what we've learned and using it t our advantage, today we can drill a Woodford Shale well for approximately $4.0 million to $4. million, record approximately 3 Bcfe of proved reserves and produce the well at a starting point o as high as 4 MMcfe per day! Confirming our approach is our drilling success – we've complete 100% of the Woodford Shale wells that we've drilled. So our costs are lower, we're finding mor producing more and are supremely confident that we'll complete our wells. This is the profile of great unconventional resource asset.

As a result of making significant strides in maturing an emerging core area like the Woodford Shal PetroQuest offers visible production and reserve growth for investors. On an acre-to-enterpris valuation, PetroQuest has nearly 32 acres of prospective Woodford Shale upside. On a relative basi this is more than any operator in this region.

Gulf of Mexico is still a growth area for us.

Promises

Our PEOPLE Deliver Solid Results

This record year cements our platform for future growth. Our growth has bee achieved by our people applying their skills and experience to delivering measurabl increases in our reserve and production rates. As I outlined earlier, our succes in 2007 is due to our people, our strategies and the quality of our properties Each contributed to making 2007 the most successful year in PetroQuest's histor I put people at the top of the list of reasons for our success. Without the energ imagination and commitment of a highly skilled and experienced team, the othe factors could not have contributed to the maximum extent possible.

It's said that the prize goes to the organization that pursues its goals hard an relentlessly every day of the year. How will 2008 exceed 2007's results? We pla to invest $200 million to $220 million to drill 140 to 150 wells. Average dail production is budgeted to be significantly higher, more than 15% higher, in 2008 We are projecting reserves to grow in excess of 30% from the drill bit alone The maturing of our emerging assets in Oklahoma, Arkansas and East Texas mean we have highly achievable, highly visible growth. We want to see production ris an average 15% or more every year for the next three years. Not considerin company or leasehold acquisitions, we expect to fund our growth through internall generated cash flow. Since 2003, we have only tapped the equity market once During that time investors have realized a return of more than 351%.

Our confidence in PetroQuest becoming a significant producer of natural ga from unconventional resources is underpinned by our patience and ability t assimilate drill-ready acreage at a reasonable price. In 2003, 25% of the nation natural gas production came from unconventional resources. That number i expected to exceed 75% before the end of this decade. In 2003, PetroQuest ha zero production from unconventional resources; during 2008, we expect almos 50% of our daily production will be categorized as unconventional.

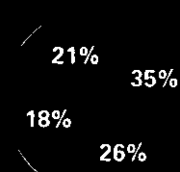
During 2007, we posted an excellent reserve replacement ratio of 170% and tota proved reserves grew 16%. Adding in reserves from all categories, PetroQuest ha more than 1.5 trillion cubic feet equivalent of natural gas and a drilling inventor of more than 4,000 locations. These reserves were calculated using an averag price of $6.52 per Mcfe. For the nine years ended 2007, we added more tha 275 Bcfe of new reserves at an average cost of $3.18 per Mcfe. For PetroQuest these figures are evidence that our growth strategies work. We fully understan the regional geology of our asset base and maximize drilling results and return through sound engineering practices.

Areas of Operation

Reserve & Production Mix

	Proved Reserves [1]	Net Unrisked Inventory [1]	Drilling Locations [1]
East Texas	47.5	263	467
Arkoma	48.1	738	3,515
South Louisiana	22.5	112	24
Offshore Gulf of Mexico	38.4	255	24

Annual Production [2]



(1) As of December 31, 2007 (reserves and inventory in Bcfe)
(2) Based on guidance for 2008 (94 MMcfe/day – 100 MMcfe/day)

Growth

We operate about 70% of our daily production.

The commodity markets are changing in our favor. We are increasing our production to realize higher revenues and cash flows. Our 2008 drilling program will be funded entirely from internal sources of capital. I marvel at how much better we get every year. Our people are leaders who seek to exceed our own goals, pursue more opportunities and over-deliver on our promises. As we celebrate our first decade as a public company, I believe PetroQuest's past offers an excellent guidepost for our future. We will be a truly great company and believe you will benefit from our efforts.

Best regards,

Charles T. Goodson

Charles T. Goodson
Chairman, President and Chief Executive Officer
February 15, 2008

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

FORM 10-K

(Mark One)
[X] Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2007
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 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, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):
[ ] Large accelerated filer [X] Accelerated filer [ ] Non-accelerated filer

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 $537,965,000 as of June 30, 2007 (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 are affiliates).

As of February 27, 2008 the registrant had outstanding 49,752,239 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 14, 2008, 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 our ability to find oil and natural gas reserves that are economically recoverable, the volatility of oil and natural gas prices, declines in the values of our properties resulting in ceiling test write-downs, our ability to replace reserves and sustain production, our estimate of the sufficiency of our existing capital sources, our ability to raise additional capital to fund cash requirements for future operations, the uncertainties involved in estimating quantities of proved oil and natural gas reserves, in prospect development and property acquisitions or dispositions and in projecting future rates of production, the timing of development expenditures and drilling of wells, hurricanes and other natural disasters, and the operating hazards attendant to the oil and gas business. 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. Before you invest in our common stock, 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 42.

PART I

ITEM 1. BUSINESS

Overview

PetroQuest Energy, Inc. is an independent oil and gas company incorporated in the State of Delaware with operations in Oklahoma, Texas, Arkansas 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. For the fourth consecutive year we achieved annual company records for production, estimated proved reserves, cash flow from operating activities and net income. During 2007, we increased these operational and financial metrics by approximately 22%, 16%, 87% and 64%, respectively, from the previous record levels achieved during 2006.

Our record results over the last four years reflect our consistent drilling success and correlate directly with the implementation of our asset diversification strategy in 2003. 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. Comparing 2007 results with those in 2003, the year we implemented our diversification strategy, we have grown production by 226% and proved reserves by 88%.

Utilizing the cash flow generated by our higher margin Gulf Coast Basin assets, and leveraging strong commodity prices, we have been able to accelerate our penetration into longer life basins in Oklahoma, Arkansas and Texas through significantly increased and successful drilling activity and selective acquisitions. Specific asset diversification activities include the 2003 acquisition of proved reserves and acreage in the Southeast Carthage Field in East Texas. In 2004, we entered the Arkoma Basin in Oklahoma by building an acreage position, drilling wells and acquiring proved reserves. During 2005 and 2006, we acquired additional acreage in Oklahoma and Texas, initiated an expanded drilling program in these areas, opened an exploration office in Tulsa, Oklahoma and divested several mature, high-cost Gulf of Mexico fields. During 2007 we continued to diversify into longer life regions by acquiring unevaluated leasehold interests in Arkansas. Drilling operations targeting the Fayetteville Shale began on this acreage in September 2007. In addition, robust drilling activity continued in Oklahoma and Texas during 2007 as we drilled 61 gross wells in these regions, realizing a 93% success rate.

Business 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, and to continue to build scale, particularly in the longer life onshore regions, through drilling and complementary acquisition activities. Operating in concentrated areas helps us to 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 and exploitation activities and higher risk and higher impact exploration activities. In addition, we will continue to pursue strategic acquisitions aimed at geographically and operationally diversifying our asset base and increasing our inventory of drilling projects. Through our portfolio diversification efforts, at December 31, 2007, approximately 61% of our estimated proved reserves were located in longer life basins in Oklahoma, Arkansas and Texas and 39% were located in the shorter life, but higher flow rate reservoirs in the Gulf Coast Basin. This compares to 52%, 50% and 45% of our proved reserves located in longer life basins at December 31, 2006, 2005 and 2004, respectively. We will continue to seek opportunities to increase our longer life onshore reserves while maintaining some exposure to shorter life, but potentially higher impact Gulf Coast reserves with a goal of having longer life reserves represent approximately 75% of our total estimated proved reserves. In terms of production diversification, during 2007, 27% of our production was derived from longer life basins (33% during the fourth quarter of 2007) versus 29% in 2006, 30% in 2005 and 16% during 2004. Our goal is to increase our production from our longer life basins to 50% of our total production.

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, exploitation and development activities. We also strive to retain operating control of the majority of our properties to control costs and timing of expenditures. At December 31, 2007, we operated approximately 59% of our total estimated proved reserves and managed the drilling and completion activities on an additional 27% of such reserves. In addition, 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.

Maintain Our Financial Flexibility. We intend to maintain a disciplined approach to financial management and a strong capital structure to execute our business plan. Historically, key components of our financial discipline have typically included funding expected exploration and development activities with cash flows from operations, establishing appropriate leverage ratios given the volatility of commodity prices, maintaining an active commodity hedging program and accessing the equity capital markets as appropriate. As we did during 2006, we may also opportunistically dispose of mature assets to provide capital for higher potential exploration and development properties that fit our long-term growth strategy.

2007 Financial and Operational Summary

During 2007, we invested $240.7 million in exploratory, development and acquisition activities as we drilled 63 gross exploratory wells and 24 gross development wells realizing an overall success rate of 87%. In September and October 2007, we issued 1,495,000 shares of our Series B cumulative convertible perpetual preferred stock (the "Series B Preferred Stock") receiving $70.7 million in net proceeds. The offering proceeds were primarily used to repay all outstanding borrowings under our credit facility.

Production during 2007 increased 22% to a company record 31.4 Bcfe. Our estimated proved reserves at December 31, 2007 increased 16% from 2006 totaling 2,342 MBbls of oil and 142,468 MMcfe of natural gas, with a pre-tax present value, discounted at 10%, of the estimated future net revenues based on constant prices in effect at year-end ("discounted cash flow") of approximately $541 million. At December 31, 2007, our standardized measure of discounted cash flows, which includes the estimated impact of future income taxes, totaled $447.3 million (see Note 11 to our financial statements).

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 2007, we expanded our evaluation of the Woodford Shale as we drilled 15 gross wells targeting this formation, achieving a 100% success rate. In total, we invested $58.5 million during 2007 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 increased to 14.7 MMcfe in the fourth quarter of 2007, a 62% increase from our 2006 average daily production. In addition to growing production, our drilling program also resulted in a 91% increase in proved reserves on our Oklahoma properties during 2007. During 2008 we expect to spend approximately $85.5 million in Oklahoma, primarily on the drilling of horizontal Woodford wells and the acquisition and integration of 3-D seismic data as we continue to develop this potentially significant formation.

Arkansas

During the second and third quarters of 2007, we closed several transactions acquiring an aggregate of approximately 16,000 net unevaluated acres in Arkansas. During late-September, we began a multi-well drilling program on this acreage targeting the Fayetteville Shale and by year-end we had participated in 12 gross wells, all of which were successful. In total we invested $28 million in Arkansas during 2007. We expect drilling activity to increase substantially throughout 2008 as we plan to spend approximately $28.5 million evaluating our acreage position in this area.

Texas

During December 2003, we acquired working interests in approximately 41,000 acres in the SE Carthage field, which had approximately 80 producing wells. During 2007, we invested $49 million on the successful drilling of 24 wells in this field. Net production from this field averaged 12.6 MMcfe per day during the fourth quarter of 2007, a 15% increase from 2006 average daily production. During 2008, we expect to invest approximately $14 million and drill 13 wells in this field.

During 2007, we made a discovery on the initial test well at our Ft. Trinidad Field. The well was placed on production during late-2007 and is currently producing approximately 1,000 barrels of oil per day. We expect to spend $11 million in this field during 2008 on the drilling of four wells.

Markets and Customers

We sell our natural gas and oil production under fixed or floating market contracts. Customers purchase all of our natural gas and oil production at current market prices. The terms of the arrangement 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.

No assurance can be given 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.

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 2007, we had three customers who accounted for 32%, 16% and 12% of our oil and natural gas revenue, respectively. For the year ended December 31, 2006, we had four customers who accounted for 22%, 14%, 12% and 11% of our oil and natural gas revenue, respectively. For the year ended December 31, 2005, we had three customers who accounted for 20%, 16% and 12% of our oil and natural gas revenue, respectively. 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.

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 tightening of natural gas supply and demand fundamentals has resulted in extremely volatile natural gas prices, which is expected to continue.

On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005 (the "2005 EPA"). 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 has proposed to amend such regulations to prohibit 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. There are legislative proposals pending in the various state legislatures which, 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 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. In most instances, the regulatory requirements relate to water and air pollution control measures. 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 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, that are subject to the federal Resource Conservation and Recovery Act ("RCRA") and comparable 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 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.

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 43,500 square feet of leased space, with exploration offices in Houston, Texas and Tulsa, Oklahoma, in approximately 5,500 square feet and 5,000 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 92 full-time employees as of December 31, 2007. 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 "Investor Relations-Corporate Reports" 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 "Investor Relations-Corporate Governance" section of our website or in print to any stockholder who requests them. On May 18, 2007, we submitted our Section 303A Annual CEO certification to the New York Stock Exchange.

ITEM 1A. RISK FACTORS

Risks Related to Our Business, Industry and Strategy

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 the majority 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.

Oil and natural gas prices are volatile, and a substantial and extended decline in the prices of oil and natural gas would likely have a material adverse effect on our financial condition.

Our revenues, results of operations, profitability and future growth, and the carrying value of our oil and natural gas properties depend to a large degree on prevailing oil and natural gas prices. 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 oil and natural gas are subject to large fluctuations in response to a variety of other factors beyond our control.

These factors include:

- relatively minor changes in the supply of or the demand for oil and natural gas;
- market uncertainty;

- the level of consumer product demand;
- weather conditions in the United States, such as hurricanes;
- the condition of the United States and worldwide economies;
- the actions of the Organization of Petroleum Exporting Countries;
- domestic and foreign governmental regulation, including price controls adopted by the Federal Energy Regulatory Commission;
- political instability in the Middle East and elsewhere;
- the price of foreign imports of oil and natural gas; and
- the price and availability of alternate fuel sources.

At various times, excess domestic and imported supplies have depressed oil and natural gas prices. We cannot predict future oil and natural gas prices and such prices may decline. Declines 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 may also reduce the amount of oil and natural gas that we can produce economically and require us to record ceiling test write-downs when prices decline. 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 and results of operations.

A substantial portion of our operations is exposed to the additional risk of tropical weather disturbances.

A substantial portion of our production and reserves is located in the Gulf of Mexico and along the Gulf Coast Basin. For example, production from our Main Pass 74 and Ship Shoal 72 fields, which are located offshore Louisiana, represented approximately 45% of our production during 2007. Operations in this area are subject to tropical weather disturbances. Some of these disturbances can be severe enough to cause substantial damage to facilities and possibly interrupt production. For example, Hurricanes Katrina and Rita impacted our South Louisiana and Texas operations in August and September of 2005, respectively, causing property damage to certain facilities, a substantial portion of which was covered by insurance. As a result, a portion of our oil and gas production was shut-in reducing our overall production volumes in the third and fourth quarters of 2005. In addition, production from our Main Pass 74 field, which represented approximately 14% of our 2007 production, was shut-in from September 2004 to January 2006 due to third party pipeline damage associated with Hurricane Ivan in September 2004. In accordance with customary industry practices, we maintain insurance against some, but not all, of these risks.

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.

There were substantial insurance claims made by the oil and gas industry as a result of hurricane damages incurred during 2005 in the Gulf Coast Basin. In certain circumstances, some insurance carriers denied claims related to hurricane damage and modified, or in some cases, restricted insurance coverage or ceased to provide certain types of insurance coverage relative to the Gulf Coast Basin. 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.

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, 2007, the aggregate amount of our outstanding indebtedness was $148.8 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 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.

We may incur from time to time debt under our bank credit facility. The borrowing base limitation under our bank credit facility is periodically redetermined and upon such redetermination, we could be forced to repay a portion of our bank debt. We may not have sufficient funds to make such repayments.

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 money 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.

We may incur substantially more debt, which may intensify the risks described above, including our ability to service our indebtedness.

Together with our subsidiaries, we may be able to incur substantially more debt in the future in connection with our acquisition, development, exploitation and exploration of oil and natural gas producing properties. Although the indenture governing our 10 3/8% notes contains restrictions on our incurrence of additional indebtedness, these restrictions are subject to a number of qualifications and exceptions, and under certain circumstances, indebtedness incurred in compliance with these restrictions could be substantial. Also, these restrictions do not prevent us from incurring obligations that do not constitute indebtedness. As of December 31, 2007, we had no borrowings under our bank credit facility and our borrowing base was $80 million. To the extent we add new indebtedness to our current indebtedness levels, the risks described above could substantially increase.

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 oil and natural gas.

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.

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

We spend and will continue to spend a substantial amount of capital for the development, exploration, acquisition and production of oil and natural gas reserves. If low 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 continue our drilling program. We may be forced to raise additional debt or equity proceeds to fund such expenditures. We cannot assure you that additional debt or equity financing or cash generated by operations will be available to meet these requirements.

Shortage of rigs, equipment, supplies or personnel may restrict our operations.

The oil and gas industry is cyclical, and at times there can be a shortage of drilling rigs, equipment, supplies and personnel. The costs and delivery times of rigs, equipment and supplies has increased in recent years as oil and natural gas prices have increased relative to historical averages. In addition, demand for, and wage rates of, qualified drilling rig crews have risen with increases in the number of active rigs in service. Shortages of drilling rigs, equipment, supplies or personnel could delay or restrict our exploration and development operations, which in turn could impair 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.

You should not place undue reliance on reserve information because reserve information represents estimates.

This document contains estimates of historical oil and natural gas reserves, and the historical estimated future net cash flows attributable to those reserves, prepared by Ryder Scott Company, L.P., our independent petroleum and geological engineers. Our estimate of proved reserves is based on the quantities of oil, gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

There are, however, numerous uncertainties inherent in estimating quantities of proved reserves and cash flows from such reserves, including factors beyond our control and the control of Ryder Scott. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of an estimate of quantities of reserves, or of cash flows attributable to these reserves, is a function of:

- the available data;
- assumptions regarding future oil and natural gas prices;
- estimated expenditures for future development and exploitation activities; and
- engineering and geological interpretation and judgment.

Reserves and future cash flows may also be subject to material downward or upward revisions based upon production history, development and exploitation activities and oil and natural gas prices. Actual future production, revenue, taxes, development expenditures, operating expenses, quantities of recoverable reserves and the value of cash flows from those reserves may vary significantly from the assumptions and estimates in this document. In calculating reserves on an Mcfe basis, oil and natural gas liquids were converted to natural gas equivalent at the ratio of six Mcf of natural gas to one Bbl of oil or natural gas liquid.

Approximately 31% of our estimated proved reserves at December 31, 2007 are undeveloped and 19% are developed, non-producing. Estimates of undeveloped and non-producing reserves, by their nature, are less certain. 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 present value of future net revenues referred to in this document is the current market value of our estimated oil and natural gas reserves. In accordance with Commission requirements, the estimated discounted future net cash flows from proved reserves are based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Any changes in consumption by 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, which is required by the Commission to be used in calculating discounted future net cash flows for reporting purposes, 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.

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 our ability to:

- dispose of assets;
- 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.

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.

We may not be able to obtain adequate financing to execute our operating strategy.

Our ability to execute our operating strategy is highly dependent on our having access to capital. 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 continue to examine the following alternative sources of long-term capital:

- 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 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 operating strategy if we cannot obtain capital from these sources.

Lower oil and natural gas prices may cause us to record ceiling test write-downs.

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, 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 stockholders' equity. The risk that we will be required to write down the carrying value of oil and natural 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.

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 natural gas and oil prices and to achieve more predictable cash flow. These financial arrangements take the form of costless collars or swap contracts and are placed with major trading counterparties whom we believe represent minimum credit risks. We cannot assure you that these trading 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 contract 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 natural gas and oil. Although oil and gas hedges increased our total oil and gas sales by approximately $9.9 million and $6.8 million during 2007 and 2006, respectively, in 2005 oil and gas hedges reduced our total oil and gas sales by approximately $15.8 million. We cannot assure you that the hedging transactions we have entered into, or will enter into, will adequately protect us from fluctuations in natural gas and oil prices.

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

Our operations are dependent upon a relatively small group of key management and technical personnel, including Charles T. Goodson, our Chairman, Chief Executive Officer and President, Stephen H. Green, our Senior Vice President-Exploration, and Arthur M. Mixon, our Executive Vice President-Exploration and Production. 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.

There is presently a shortage of qualified geologists and geophysicists necessary to fill our requirements and the requirements of the oil and gas industry, and the market for such individuals is highly competitive. Our inability to hire or retain the services of such individuals could have a 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.

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.

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 be highly volatile. 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 granting 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, 2007, we had reserved approximately 2.6 million shares of common stock for issuance under outstanding options and 5,147,734 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 2. PROPERTIES

For a description of the Company's recent acquisition, exploration and development activities, see Item 1. Business–2007 Financial and Operational Summary.

Oil and Gas Reserves

The following table sets forth certain information about our estimated proved reserves as of December 31, 2007.

	Proved Developed	Proved Undeveloped	Total Proved
Oil (MBbls)	2,070	272	2,342
Natural Gas and NGL (MMcfe)	95,639	46,829	142,468
Estimated pre-tax future net cash flows	$620,685,527	$158,709,153	$779,394,680
Discounted pre-tax future net cash flows	$471,555,642	$69,095,841	$540,651,483

At December 31, 2007, our standardized measure of discounted cash flows, which includes the estimated impact of future income taxes, totaled $447.3 million (see Note 11 to our financial statements). Ryder Scott Company, L.P., our independent petroleum engineers, prepared the estimates of proved reserves and future net cash flows (and present value thereof) attributable to such proved reserves at December 31, 2007. Reserves were estimated using oil and gas prices and production and development costs in effect at December 31, 2007 without escalation, and were prepared in accordance with Securities and Exchange Commission regulations regarding disclosure of oil and gas reserve information. The product prices used in developing the above estimates averaged $96.83 per Bbl of oil and $6.52 per Mcfe of gas. The above cash flow amounts include a reduction for estimated plugging and abandonment costs that has been reflected as a liability on our balance sheet at December 31, 2007, in accordance with Statement of Financial Accounting Standards No. 143.

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

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,		
	2007	2006	2005
Production:			
Oil (Bbls)	1,079,672	694,724	665,400
Gas (Mcfe)	24,965,789	21,528,323	12,058,377
Total Production (Mcfe)	31,443,821	25,696,667	16,050,777
Average sales prices (1):			
Oil (per Bbl)	$ 70.52	$ 60.91	$ 45.76
Gas (per Mcfe)	7.21	7.04	7.47
Per Mcfe	8.15	7.54	7.51
Average Production Cost per Mcfe (2)	$ 1.27	$ 1.61	$ 1.54

(1) Includes the effects of hedges.

(2) Production costs include lease operating costs and 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:

	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Exploration:						
Productive	54	26.12	37	15.82	32	14.82
Non-productive	9	2.86	4	0.95	3	1.53
Total	63	28.98	41	16.77	35	16.35
Development:						
Productive	22	7.89	66	26.40	46	30.90
Non-productive	2	0.15	6	2.89	5	4.29
Total	24	8.04	72	29.29	51	35.19

We owned working interests in 12 gross (7 net) producing oil wells and 675 gross (253 net) producing gas wells at December 31, 2007. Of the 687 gross productive wells at December 31, 2007, 21 had dual completions. At December 31, 2007, we had 12 gross wells in progress.

Leasehold Acreage

The following table shows our approximate developed and undeveloped (gross and net) leasehold acreage as of December 31, 2007:

	Leasehold Acreage			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Mississippi	721	458	-	-
Alabama	709	468	6,832	4,511
Arkansas	280	91	51,236	17,250
Louisiana	6,178	2,120	15,709	4,356
Oklahoma	71,603	26,686	14,262	13,475
Texas	46,762	25,392	35,045	31,176
Federal Waters	35,694	15,321	60,278	35,651
Total	161,947	70,536	183,362	106,419

Leases covering 16% of our gross undeveloped acreage will expire in 2008, 23% in 2009, 28% in 2010 and 33% 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.

ITEM 3. LEGAL PROCEEDINGS

PetroQuest is involved in litigation relating to claims arising out of its operations in the normal course of business, including workmen'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.

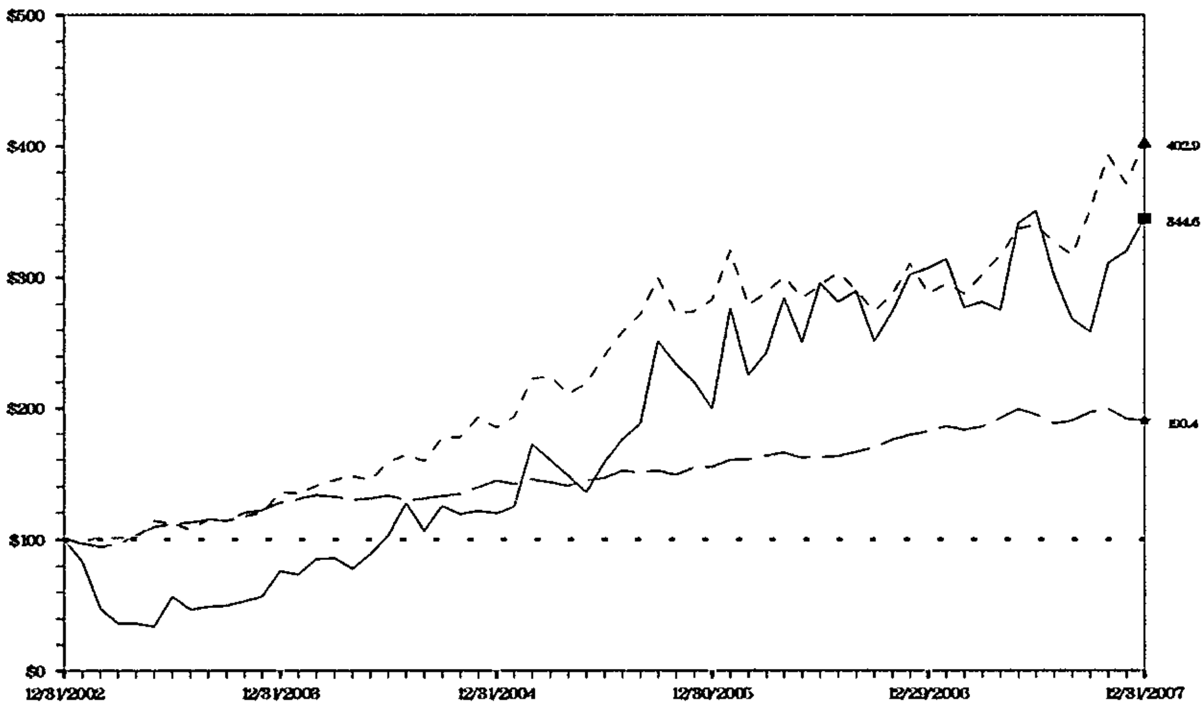
ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

There were no matters submitted to a vote of security holders during the fourth quarter of 2007.

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, 2007.



Legend

Symbol	Total Returns for:	12/2002	12/2003	12/2004	12/2005	12/2006	12/2007
——— ■	PETROQUEST ENERGY INC	100.0	76.4	119.5	199.5	307.0	344.6
— — ★	NYSE/AMEX Stock Market (US Companies)	100.0	127.8	144.7	155.1	182.3	190.4
- - - - ▲	NYSE Stocks (SIC 1310—1319 US Companies) Crude Petroleum and Natural Gas	100.0	135.7	185.2	283.1	287.8	402.9

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:

	NYSE Stock Market	
	High	Low
2006		
1st Quarter	$ 12.11	$ 8.25
2nd Quarter	13.00	9.35
3rd Quarter	12.58	9.55
4th Quarter	14.40	9.87
2007		
1st Quarter	$ 13.57	$ 10.08
2nd Quarter	15.99	11.39
3rd Quarter	15.13	10.02
4th Quarter	14.99	10.69

As of February 27, 2008, there were 447 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, by 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, 2007.

	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, 2007	-	-	-	-
November 1 - November 30, 2007	-	-	-	-
December 1 - December 31, 2007	11,458	$14.47	-	-

(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, 2007 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,				
	2007	2006 (a)	2005	2004	2003 (b)
	(in thousands except per share data)				
Revenues	$ 263,674	$ 200,544	$ 124,594	$ 84,868	$ 48,688
Net income available to common stockholders	39,245	23,986	21,417	16,348	3,640
Net income available to common stockholders per share:					
Basic	0.82	0.50	0.46	0.37	0.08
Diluted	0.79	0.49	0.44	0.35	0.08
Oil and gas properties, net	554,850	431,814	365,183	211,683	160,229
Total assets	644,347	518,290	431,470	231,617	176,384
Long-term debt	148,755	195,537	158,340	38,500	22,200
Stockholders' equity	302,317	189,711	144,537	121,277	107,727

(a) During 2006, the Company adopted SFAS No. 123(R). Amounts recognized during 2006 relative to SFAS 123(R) reduced net income by $3.7 million, or $0.08 per share.
(b) During 2003, the Company adopted SFAS No. 143. The cumulative effect of adoption resulted in a gain of $849,000, or $0.02 per share.

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, which from the commencement of operations in 1985 through 2002, was 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, and leveraging strong commodity prices, we have been able to accelerate our penetration into longer life basins in Oklahoma, Arkansas and Texas through significantly increased and successful drilling activity and selective acquisitions. Specific asset diversification activities included the 2003 acquisition of proved reserves and acreage in the Southeast Carthage Field in East Texas. In 2004, we entered the Arkoma Basin in Oklahoma by building an acreage position, drilling wells and acquiring proved reserves. During 2005 and 2006, we acquired additional acreage in Oklahoma and Texas, initiated an expanded drilling program in these areas, opened an exploration office in Tulsa, Oklahoma and divested several mature, high-cost Gulf of Mexico fields. During 2007 we continued to diversify into longer life regions by acquiring unevaluated leasehold interests in Arkansas. Drilling operations targeting the Fayetteville Shale began on this acreage in September 2007. In addition, robust drilling activity continued in Oklahoma and Texas as we drilled 61 gross wells in these regions during 2007, realizing a 93% success rate. Through these efforts, at December 31, 2007, 61% of our estimated proved reserves were located in longer life basins as compared to 52% at December 31, 2006 and 50% at December 31, 2005. During 2007, 27% of our production was derived from longer life basins (33% during the fourth quarter of 2007) versus 29% and 30% during 2006 and 2005, respectively.

For the fourth consecutive year we achieved annual company records for production, estimated proved reserves, cash flow from operating activities and net income. During 2007 we increased these operational and financial metrics by 22%, 16%, 87% and 64%, respectively, from the previous record levels achieved during 2006. Our record results over the last four years reflect our consistent drilling success and correlate directly with the implementation of our asset diversification strategy during 2003. Comparing 2007 results with those in 2003, we have grown production by 226% and proved reserves by 88%. During 2007, we invested $240.7 million in exploratory, development and acquisition activities as we drilled 87 gross wells realizing an overall success rate of 87%.

Critical Accounting Policies and Estimates

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, 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. Declines in prices or reserves could result in a future write-down of oil and gas properties.

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 decline, even for only a short period of time, or if we have downward revisions to our estimated proved reserves, it is possible that 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.

Reserve Estimates

Our estimates of proved oil and gas reserves constitute quantities that we are reasonably certain of recovering in future years. 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, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and 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, all of which may in fact vary considerably from actual results. 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. For these reasons, estimates of the economically recoverable quantities of expected oil and gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows may vary substantially. 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. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variance may be material.

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 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, 2007, our derivative instruments were considered effective cash flow hedges.

Estimating the fair value of hedging derivatives requires complex calculations incorporating estimates of future prices, discount rates and price movements. As a result, we obtain the fair value of our commodity derivatives from the counterparties to those contracts. Because the counterparties are market makers, they are able to provide us with a price at which they would be willing to settle such contracts as of the given date. We believe the values provided by our counterparties represent the most accurate estimate of fair value of the contracts.

New Accounting Standards

In July 2006, the FASB issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" ("FIN 48"). FIN 48 is an interpretation of SFAS 109, "Accounting for Income Taxes," and it seeks to reduce the diversity in practice associated with certain aspects of measurement and accounting for income taxes and requires expanded disclosure with respect to the uncertainty in income taxes. FIN 48 is effective for fiscal years beginning after December 15, 2006. Accordingly, we adopted FIN 48 on January 1, 2007. The adoption of FIN 48 did not have an effect on our financial position or results of operations. We recognize interest and penalties related to uncertain tax positions in income tax expense. As of the date of adoption and December 31, 2007, we did not have any unrecognized tax benefits or accrued interest or penalties related to uncertain tax positions. The tax years from 2002 through 2006 remain open to examination by the tax jurisdictions to which we are subject.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" ("SFAS No. 157"). SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosure about fair value measurements. SFAS No. 157 will be effective for financial statements issued for fiscal years beginning after November 15, 2007. In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Liabilities – Including an amendment of FASB Statement No. 115" ("SFAS No. 159"). SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value. This statement will be effective for us on January 1, 2008. We do not anticipate that the implementation of these new standards will have a material effect on our financial statements.

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, 2007, 2006 and 2005. Our historical results are not necessarily indicative of results to be expected in future periods.

	Year Ended December 31,		
	2007	2006	2005
Production:			
Oil (Bbls)	1,079,672	694,724	665,400
Gas (Mcfe)	24,965,789	21,528,323	12,058,377
Total Production (Mcfe)	31,443,821	25,696,667	16,050,777
Sales:			
Total oil sales	$ 76,138,234	$ 42,317,332	$ 30,446,897
Total gas sales	180,084,794	151,544,026	90,105,054
Total oil and gas sales	$ 256,223,028	$ 193,861,358	$ 120,551,951
Average sales prices:			
Oil (per Bbl)	$ 70.52	$ 60.91	$ 45.76
Gas (per Mcfe)	7.21	7.04	7.47
Per Mcfe	8.15	7.54	7.51

The above sales and average sales prices include increases (reductions) to revenue related to the settlement of gas hedges of $10,713,000, $9,634,000 and ($10,242,000) and oil hedges of ($791,000), ($2,785,000) and ($5,572,000) for the years ended December 31, 2007, 2006 and 2005, respectively.

Comparison of Results of Operations for the Years Ended December 31, 2007 and 2006

Net income available to common stockholders for the year ended December 31, 2007 increased 64% to $39,245,000, as compared to $23,986,000 for the year ended December 31, 2006. The results were attributable to the following components:

Production

Oil production during 2007 totaled 1,080 MBbls, a 55% increase from 2006, while natural gas production increased 16% to 25 Bcfe from 2006 gas production of 21.5 Bcfe. On a gas equivalent basis, production for 2007 totaled 31.4 Bcfe, a 22% increase from the 2006 period.

Throughout 2006, we successfully drilled and recompleted several wells at our Ship Shoal 72 Field, which produces substantial oil volumes. As a result of drilling success and the improvement in throughput from a new main field pipeline installed in late 2006, production from Ship Shoal 72 totaled 9.8 Bcfe, or approximately 31% of total company production during 2007, as compared to only 4.5 Bcfe during 2006. In addition, continued drilling success in Oklahoma and Texas resulted in increased production during 2007 from these basins. The increase in production during 2007 was partially offset by the sale of several Gulf of Mexico fields in November 2006. Production from the properties sold in 2006 totaled 1.7 Bcfe.

During the five year period ended December 31, 2007, we have realized a 90% success rate on 329 gross wells drilled. Assuming there are no material production shut-ins during 2008 and we are able to maintain our historically high drilling success rates with our 2008 drilling program, we expect that our production will continue to increase during 2008.

Prices

Average oil prices per barrel during 2007 were $70.52 versus $60.91 during 2006. Average gas prices per Mcf were $7.21 during 2007 as compared to $7.04 during 2006. Stated on a gas equivalent basis, unit prices received during 2007 were 8% higher as compared to the prices received during 2006.

Revenue

Oil and gas sales during 2007 increased 32% to $256,223,000, as compared to $193,861,000 during 2006 as a result of increased production volumes and higher realized prices. Assuming commodity prices remain at current levels, we expect that our revenues would continue to increase as we expect to grow our production during 2008 through drilling.

During 2007, gas gathering revenue and other income totaled $7,451,000 as compared to $6,683,000 during 2006. The increase in 2007, as compared to 2006, is the result of increased gas volumes being transported through the gas gathering systems.

Expenses

Lease operating expenses during 2007 decreased to $31,965,000 as compared to $34,735,000 during 2006. Lease operating costs in 2006 included $5,979,000 of costs related to the Gulf of Mexico properties sold in November 2006. We expect that operating expenses during 2008 will exceed 2007 amounts as a result of the expected increase in the number of producing wells in which we have an interest. However, on a per unit basis, we expect that operating costs will generally approximate 2007 results.

Production taxes increased to $7,859,000 during 2007 from $6,576,000 during 2006. The increase in 2007 production taxes is primarily due to increased production from our Oklahoma, Texas and onshore Louisiana properties, partially offset by the 28% reduction in the Louisiana severance tax rate effective July 1, 2007.

General and administrative expenses during 2007 totaled $21,162,000, as compared to expenses of $15,122,000 during 2006. Included in general and administrative expenses for the years ended December 31, 2007 and 2006 was share based compensation expense relative to SFAS 123(R) as follows (in thousands):

	Years Ended December 31, 2007	Years Ended December 31, 2006
Stock options:		
Incentive Stock Options	$ 1,250	$ 526
Non-Qualified Stock Options	1,869	1,344
Restricted stock	6,699	3,781
Share based compensation	$ 9,818	$ 5,651

Excluding the impact of share based compensation expense, the resulting 20% increase in general and administrative expenses was primarily attributable to the 31% increase in our staffing during 2007 necessary to manage our increased operational activity. We capitalized $7,522,000 and $6,191,000 of general and administrative costs during 2007 and 2006, respectively.

Depreciation, depletion and amortization ("DD&A") expense on oil and gas properties for 2007 increased 40% to $116,384,000, as compared to $82,928,000 in 2006. The increase in DD&A expense is the result of the growth in our oil and gas properties over the last three years from our significantly expanded drilling activity and several property acquisitions. On an Mcfe basis, the DD&A rate on oil and gas properties totaled $3.70 per Mcfe during 2007 as compared to $3.23 per Mcfe for 2006. The increase in our DD&A expense per Mcfe is primarily due to increased costs to drill for, develop and acquire oil and gas reserves and the impact of six unsuccessful wells drilled in the Gulf Coast Basin during 2007. Assuming commodity prices remain at current levels, we would expect the costs to drill for, develop and acquire oil and gas reserves to generally approximate 2007 levels.

During September and October 2007, we issued a total of 1,495,000 shares of Series B cumulative convertible perpetual preferred stock (the "Series B Preferred Stock"). At December 31, 2007, $1,374,000 had been accrued in connection with the initial dividend paid on January 15, 2008. Interest expense, net of amounts capitalized on unevaluated assets, totaled $13,393,000 during 2007 versus $14,513,000 during 2006. The decrease in interest expense in 2007 is the result of the repayment of our bank borrowings in September 2007 with proceeds received from the issuance of the Series B Preferred Stock. We capitalized $6,539,000 and $4,650,000 of interest during 2007 and 2006, respectively.

Income tax expense of $23,664,000 was recognized during 2007 as compared to $14,604,000 during 2006. The increase is primarily due to the higher operating profit during 2007. 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.

Comparison of Results of Operations for the Years Ended December 31, 2006 and 2005

Net income available to common stockholders for the year ended December 31, 2006 increased 12% to $23,986,000, as compared to $21,417,000 for the year ended December 31, 2005. The results were attributable to the following components:

Production

Oil production during 2006 totaled 694,724 barrels, a 4% increase from 2005, while natural gas production increased 78% to 21.5 Bcfe from 2005 gas production of 12.1 Bcfe. On a gas equivalent basis, production for 2006 totaled 25.7 Bcfe, a 60% increase from the 2005 period.

Contributing to the increase in production during 2006 was the restoration of production at our Main Pass 74 field in January 2006 and production attributable to the 91% drilling success rates we achieved during each of 2005 and 2006. Production from Main Pass 74 accounted for 18% of our total production for 2006. Production gains during 2006 were offset by the shut-in of the majority of production at our Ship Shoal Block 72 field during October and November 2006 due to work on the main field pipeline and the sale of certain mature Gulf of Mexico properties in November 2006. Production from Ship Shoal Block 72 accounted for approximately 20% of our total production during the nine months ended September 30, 2006. Production during the third and fourth quarters of 2005 was negatively impacted by Hurricanes Katrina and Rita.

During 2006, 84% of our total production was natural gas as compared to 75% during 2005. This shift towards natural gas is primarily the result of our expanded operations in Texas and Oklahoma where the production is primarily natural gas. Also contributing to the increase in gas as a percent of total production was the shut-in of Ship Shoal 72 discussed above. Ship Shoal 72, which was brought back on-line in December 2006, produces a substantial portion of our total oil volumes.

Prices

Average oil prices per barrel during 2006 were $60.91 versus $45.76 during 2005. Average gas prices per Mcf were $7.04 during 2006 as compared to $7.47 during 2005. Stated on a gas equivalent basis, unit prices received during 2006 were essentially flat as compared to the prices received during 2005.

Revenue

Oil and gas sales during 2006 increased 61% to $193,861,000 from $120,552,000 during 2005 as a result of increased production volumes.

During 2006, gas gathering revenue and other income totaled $6,683,000 as compared to $4,042,000 during 2005. The increase in 2006, as compared to 2005, is the result of increased gas volumes being transported through the gas gathering systems, as well as a full year of operations, as the majority of our gas gathering assets were acquired in connection with certain purchases of oil and gas properties during mid-2005.

Expenses

Lease operating expenses during 2006 increased to $34,735,000 as compared to $20,972,000 during 2005. However, on an Mcfe basis, lease operating expenses totaled $1.35 per Mcfe in 2006, only a 3% increase from the $1.31 per Mcfe of operating costs in 2005. Operating costs during 2006 were higher than in 2005 due to the increases in costs for oil field related services prevalent throughout the industry, such as labor, transportation, insurance and materials.

Production taxes increased to $6,576,000 during 2006 from $3,764,000 during 2005. The increase in 2006 production taxes is primarily due to significantly increased production from our Oklahoma, Texas and onshore Louisiana properties, as well as a 48% increase in the Louisiana severance tax rate effective July 1, 2006. In addition, Main Pass 74, which is located in Louisiana state waters and is thus subject to production taxes, was brought back on-line in January 2006.

Gas gathering costs during 2006 totaled $3,637,000. Because the majority of our gas gathering assets were acquired in connection with purchases of certain oil and gas properties in mid-2005, gas gathering costs during 2005 only totaled $1,246,000.

General and administrative expenses during 2006 totaled $15,122,000 as compared to $7,347,000 during 2005, net of amounts capitalized of $6,191,000 and $4,807,000, respectively. Included in 2006 general and administrative expenses was $5,651,000 attributable to share based compensation recognized in connection with the adoption of SFAS 123(R) on January 1, 2006. Excluding the impact of the adoption of SFAS 123(R), the increase in general and administrative expenses is primarily due to the 11% increase in our staffing level during 2006 in order to accommodate our increased operational activities.

Depreciation, depletion and amortization ("DD&A") expense on oil and gas properties for 2006 increased 95% to $82,928,000 as compared to $42,513,000 in 2005. The increase in DD&A expense is the result of the growth in our oil and gas properties during 2006 and 2005 resulting from our significantly expanded drilling activity and several property acquisitions during 2005. On an Mcfe basis, the DD&A rate on oil and gas properties totaled $3.23 per Mcfe during 2006 as compared to $2.65 per Mcfe for 2005. The increase in our DD&A expense per Mcfe is primarily due to increased costs to drill for, develop and acquire oil and gas reserves and the impact of four unsuccessful wells drilled in the Gulf Coast Basin during 2006.

Interest expense, net of amounts capitalized on unevaluated assets, totaled $14,513,000 during 2006 versus $12,371,000 during 2005. Included in interest expense during 2005 was a charge of $2,575,000 primarily related to previously deferred financing costs, which were written off in connection with the repayment of amounts outstanding under our credit facilities. The increase in interest expense, as compared to 2005, is primarily due to the impact of a full year of interest on our $150 million 10 3/8% Senior Notes due 2012 (the "Notes") during 2006, which were issued during the second quarter of 2005. We capitalized $4,650,000 and $2,912,000 of interest during 2006 and 2005, respectively.

Income tax expense of $14,604,000 was recognized during 2006 as compared to $12,477,000 during 2005. The increase is primarily due to the higher operating profit during 2006. 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 properties. During September and October 2007, we received approximately $71 million in net proceeds from the issuance of 1,495,000 shares of our Series B Preferred Stock. The offering proceeds were primarily used to repay all outstanding borrowings under our credit facility in order to provide liquidity for our ongoing diversification efforts.

At December 31, 2007, we had a working capital deficit of $43.7 million compared to a deficit of $7.9 million at December 31, 2006. The decline in our working capital was primarily due to the $11.2 million reduction in the estimated fair value of our derivative instruments, which is primarily the result of the expiration of several hedge contracts and higher estimated commodity prices, and the $31.4 million increase in our accounts payable to vendors, net of cash and cash equivalents on hand, which is a result of increased operational activity. We believe that our working capital balance should be viewed in conjunction with availability of borrowings under our bank credit facility when measuring liquidity. As a result of the application of the net proceeds from the sale of our Series B Preferred Stock, at December 31, 2007 we had no borrowings outstanding under our bank credit facility and $80 million of borrowing capacity.

Source of Capital: Operations

Net cash flow from operations increased from $119,370,000 during 2006 to $223,729,000 in 2007. The increase in operating cash flow was primarily attributable to our growth in production during 2007.

Source of Capital: Debt

During 2005, we issued 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, 2007, $1.9 million had been accrued in connection with the May 15, 2008 interest payment. At December 31, 2007, we were in compliance with all of the covenants under the Notes.

On November 18, 2005, we and our wholly owned subsidiary, PetroQuest Energy, L.L.C., entered into the Second Amended and Restated Credit Agreement. The credit agreement provides for a $100 million revolving credit facility that permits us to borrow amounts based on the available borrowing base as determined in the credit facility. The credit facility also allows us to use up to $15 million of the borrowing base for letters of credit. The credit facility matures on November 19, 2009.

The credit facility is secured by, among other things, a lien on at least 90% of the PDP present value and at least 80% of the aggregate proved reserves of our oil and gas properties. PDP present value means the present value discounted at nine percent of the future net revenues attributable to producing reserves. The borrowing base under the credit facility is based primarily upon the bi-annual valuation of our mortgaged oil and gas properties. The borrowing base is currently $80 million and the next scheduled borrowing base re-determination will be on April 1, 2008 and we or the lenders may request additional borrowing base re-determinations. As of December 31, 2007, we did not have any borrowings outstanding under the credit facility and we were in compliance with all of the covenants therein. During January and February 2008, we borrowed $37.5 million under the credit facility to fund the acquisition of additional interests in our Ft. Trinidad Field and for other oil and gas activities.

Outstanding balances on the credit facility bear interest at either the alternate base rate plus a margin (based on a sliding scale of 0.125% to 0.875% based on borrowing base usage) or the Eurodollar rate plus a margin (based on a sliding scale of 1.375% to 2.125% depending on borrowing base usage). The alternate base rate is equal to the higher of the JPMorgan Chase prime rate or the Federal Funds Effective Rate plus 0.5% per annum, and the Eurodollar rate is equal to the applicable British Bankers' Association LIBOR rate for deposits in U.S. dollars.

We are subject to certain restrictive financial covenants under the credit facility, including a maximum ratio of consolidated indebtedness to annualized consolidated EBITDA, determined on a rolling four quarter basis of 3.0 to 1 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 facility also includes customary restrictions with respect to liens, indebtedness, loans and investments, material changes in our business, asset sales or leases or transfers of assets, restricted payments such as distributions and dividends, mergers or consolidations, transactions with affiliates and rate management transactions.

Natural gas and oil 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 natural gas and oil 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. Reduced cash flow may also make it difficult to incur debt, other than under our bank credit facility, because of the restrictive covenants in the indenture governing the Notes. 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 natural gas and oil prices.

Source of Capital: Issuance of Securities

During September and October 2007, we issued a total of 1,495,000 shares of Series B Preferred Stock resulting in net proceeds to us of approximately $71 million. Cash dividends are payable quarterly in the amount of $0.8594 per share of Series B Preferred Stock. Based on the total of 1,495,000 shares of Series B Preferred Stock issued, the annual dividend payment, if declared and paid, is expected to be approximately $5.1 million. In January 2008, we declared and paid our first dividend totaling $1.6 million.

Each share of convertible preferred stock is convertible at the holder's option at any time initially into 3.4433 shares of our common stock (based on an initial conversion price of $14.52 per share of common stock, subject to adjustment), subject to our right to settle all or a portion of the conversion in cash. On or after October 20, 2010, we may, at our option, cause the Series B Preferred Stock to be automatically converted at the applicable conversion rate if the closing price of our common stock for 20 trading days within a period of 30 consecutive trading days equals or exceeds 130% of the conversion price. See Note 2 of the Notes to Consolidated Financial Statements for a summary of certain terms of the Series B Preferred Stock.

After giving effect to the issuance of the Series B Preferred Stock, we have approximately $125 million remaining under an effective universal shelf registration statement relating to the potential public offer and sale of any combination of debt securities, common stock, 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 capital to be reinvested in higher rate of return projects or in projects that have longer estimated lives. During August 2007, we announced that we were seeking strategic alternatives with respect to our gas gathering assets located in Oklahoma. One of those alternatives includes the potential sale of these assets during 2008. There can be no assurance that we will be able to sell any of our assets.

Use of Capital: Exploration and Development

Our 2008 capital budget, which excludes acquisitions and capitalized interest and general and administrative costs, is expected to range between $200 million and $220 million. Based on our outlook of commodity prices and production, we believe that we will be able to fund our planned 2008 exploration and development activities with cash on hand, cash flow from operations and available bank borrowings. Our future exploration and development activities, or any significant acquisitions, could require additional financings, which may include sales of additional equity or debt securities, additional bank borrowings, sales of properties, 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 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, 2007 (in thousands):

	Total	2008	2009	2010	2011	2012	After 2012
10 3/8% senior notes (1)	$ 218,088	$ 15,563	$ 15,563	$ 15,563	$ 15,563	$ 155,836	$ -
Purchase obligations (2)	20,525	11,625	8,900	-	-	-	-
Operating leases (3)	2,131	951	909	189	71	11	-
Capital projects (4)	17,451	5,280	581	785	111	1,429	9,265
Total	$ 258,195	$ 33,419	$ 25,953	$ 16,537	$ 15,745	$ 157,276	$ 9,265

(1) Includes principal and interest.
(2) Consists of commitments for the rental of drilling rigs and seismic data acquisition obligations.
(3) Consists primarily of leases for office space and leases for equipment rentals.
(4) Consists of estimated future obligations to abandon our leased 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 2008, a 10% decline in the estimated average prices we receive for our crude oil and natural gas production would have an approximate $30 million impact on our 2008 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 counterparts 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 counterparts this difference multiplied by the quantity hedged. During 2007, we received from the counterparties to our derivative instruments approximately $9.9 million 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.

As of December 31, 2007, we had entered into the following oil and gas hedge contracts accounted for as cash flow hedges:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
2008	Costless Collar	20,000 Mmbtu	$7.75 - 8.78
Crude Oil:			
2008	Costless Collar	400 Bbls	$70.00 - 75.55

At December 31, 2007, we recognized a liability of approximately $0.7 million related to the estimated fair value of these derivative instruments. Based on estimated future commodity prices as of December 31, 2007, we would realize a $0.4 million loss, net of taxes, as a reduction to oil and gas sales during the next 12 months. These losses are expected to be reclassified based on the schedule of oil and gas volumes stipulated in the derivative contracts.

In January and February 2008, we entered into the following oil and gas hedge contracts accounted for as cash flow hedges:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
February-December 2008	Costless Collar	7,500 Mmbtu	$7.50 - 8.98
March-June 2008	Costless Collar	10,000 Mmbtu	$8.25 - 8.75
April-December 2008	Costless Collar	7,500 Mmbtu	$9.00 - 10.35
Crude Oil:			
February-June 2008	Costless Collar	400 Bbls	$85.00 - 115.00

At December 31, 2007, we had no debt outstanding that was subject to a floating interest rate. As a result, the potential effect of rising interest rates during 2008 is not expected to be material.

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.

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, 2007 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, 2007. 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, 2007 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, 2007 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, 2007.

February 29, 2008

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

/s/ Michael O. Aldridge
Michael O. Aldridge
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, 2007, 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, 2007, 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, 2007 and 2006, and the related consolidated statements of income, stockholders' equity, cash flows and comprehensive income for each of the three years in the period ended December 31, 2007 and our report dated February 29, 2008 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
New Orleans, Louisiana
February 29, 2008

ITEM 9B. OTHER INFORMATION

NONE

PART III

ITEMS 10, 11, 12, 13 & 14

For 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, see the definitive Proxy Statement of PetroQuest Energy, Inc. relating to the Annual Meeting of Stockholders to be held May 14, 2008, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

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-25 of this Form 10-K:

Report of Independent Registered Public Accounting Firm
Consolidated Balance Sheets as of December 31, 2007 and 2006
Consolidated Statements of Income for the three years ended December 31, 2007
Consolidated Statements of Cash Flows for the three years ended December 31, 2007
Consolidated Statements of Stockholders' Equity for the three years ended December 31, 2007
Consolidated Statements of Comprehensive Income for the three years ended December 31, 2007
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).

2.2 Agreement and Plan of Merger dated April 12, 2005, among PetroQuest Energy, Inc., TDC Acquisition Sub LLC and TDC Energy LLC (incorporated herein by reference to Exhibit 2.1 to Form 8-K filed April 13, 2005).

2.3 Purchase and Sale Agreement, dated as of April 13, 2005 between Staab Holdings, L.L.C. and PetroQuest Energy, LLC (incorporated herein by reference to Exhibit 2.1 to Form 8-K filed April 22, 2005).

2.4 Purchase and Sale Agreement, dated as of April 7, 2005, among MAKO Resources, LLC, Golden Gas Service Company and PetroQuest Energy, LLC (incorporated herein by reference to Exhibit 2.2 to Form 8-K filed April 22, 2005).

2.5 Purchase and Sale Agreement, dated as of April 7, 2005, between Golden Gas Service Company and PetroQuest Energy, LLC (incorporated herein by reference to Exhibit 2.3 to Form 8-K filed April 22, 2005).

2.6 Purchase and Sale Agreement, dated as of April 7, 2005, between Golden Gas Service Company and PetroQuest Energy, LLC (incorporated herein by reference to Exhibit 2.4 to Form 8-K filed April 22, 2005).

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

3.2 Bylaws of the Company, as amended of December 20, 2007 (incorporated herein by reference to Exhibit 3.1 to Form 8-K filed December 21, 2007).

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

3.4 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).

3.5 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 Warrant to Purchase Common Shares of PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 4.1 to Form 8-K filed December 29, 2003).

4.2 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).

4.3 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).

4.4 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).

4.5 Registration Rights Agreement dated April 12, 2005, between PetroQuest Energy, Inc. and Macquarie Bank Limited (incorporated herein by reference to Exhibit 4.1 to Form 8-K filed April 13, 2005).

† 10.1 PetroQuest Energy, Inc. 1998 Incentive Plan, as amended and restated effective March 16, 2006 (the "Incentive Plan") (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed May 19, 2006).

† 10.2 Form of Incentive Stock Option Agreement for executive officers (including Charles T. Goodson, Arthur M. Mixon, III, Michael O. Aldridge, Daniel G. Fournerat and Stephen H. Green) under the Incentive Plan (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed May 19, 2006).

† 10.3 Form of Restricted Stock Agreement for executive officers (including Charles T. Goodson, Arthur M. Mixon, III, Michael O. Aldridge, Daniel G. Fournerat and Stephen H. Green) under the Incentive Plan (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed May 19, 2006).

† 10.4 PetroQuest Energy, Inc. Annual Cash Bonus Plan (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed August 18, 2006).

10.5 Amended and Restated Credit Agreement, dated as of May 14, 2003, by and between PetroQuest Energy, LLC. PetroQuest Energy, Inc., Bank One, NA, Banc One Capital Markets, Inc., and certain other Lenders (incorporated herein by reference to Exhibit 10.1 to Form 10-Q filed August 13, 2003).

10.6 Guaranty dated May 14, 2003, between PetroQuest Energy, Inc. and Bank One, NA, as Agent for the Lenders (incorporated herein by reference to Exhibit 10.2 to Form 10-Q filed August 13, 2003).

10.7 First Amendment to Amended and Restated Credit Agreement dated as of November 6, 2003, by and among PetroQuest Energy, L.L.C., PetroQuest Energy, Inc.; Bank One, N.A., and Union Bank of California, N.A. (incorporated herein by reference to Exhibit 10.4 to Form 10-Q filed November 13, 2003).

10.8 Second Amendment to Amended and Restated Credit Agreement dated as of December 23, 2003, by and among PetroQuest Energy, L.L.C., PetroQuest Energy, Inc., and Bank One, N.A. (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed December 29, 2003).

10.9 Third Amendment to Amended and Restated Credit Agreement dated as of July 27, 2004, by and among PetroQuest Energy, L.L.C., PetroQuest Energy, Inc., and Bank One, N.A. (incorporated herein by reference to Exhibit 10.1 to Form 10-Q filed July 30, 2004).

10.10 Fourth Amendment to Amended and Restated Credit Agreement dated as of October 14, 2004 by and between PetroQuest Energy, LLC, PetroQuest Energy, Inc. and Bank One, N.A. (incorporated herein by reference to Exhibit 10.1 on Form 8-K filed October 19, 2004).

10.11 Fifth Amendment to Amended and Restated Credit Agreement entered into as of November 3, 2004 by and between PetroQuest Energy, LLC, PetroQuest Energy, Inc., Pittrans Inc. (a wholly owned subsidiary of PetroQuest Energy, LLC) and Bank One, N.A. (incorporated herein by reference to Exhibit 10.1 on Form 8-K filed November 15, 2004).

10.12 Sixth Amendment to Amended and Restated Credit Agreement dated April 12, 2005, by and among PetroQuest Energy, LLC, PetroQuest Energy, Inc., Pittrans Inc., TDC Acquisition Sub LLC, and JP Morgan Chase Bank, N.A. (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed April 13, 2005).

10.13 Seventh Amendment to Amended and Restated Credit Agreement dated May 9, 2005, by and among PetroQuest Energy, LLC, PetroQuest Energy, Inc., Pittrans Inc., TDC Energy LLC, and JP Morgan Chase Bank, N.A. (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed May 11, 2005).

10.14 Eighth Amendment to Amended and Restated Credit Agreement dated June 17, 2005, by and among PetroQuest Energy, LLC, PetroQuest Energy, Inc., Pittrans Inc., TDC Energy LLC, and JP Morgan Chase Bank, N.A., Guaranty Bank, FSB and Calyon New York Branch (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed June 17, 2005).

10.15 Second Amended and Restated Credit Agreement dated as of November 18, 2005, among PetroQuest Energy, LLC, PetroQuest Energy, Inc., JP Morgan Chase Bank, N.A. as lender, agent and issuer of letters of credit, Macquarie Bank Limited as lender, and Calyon New York Branch as lender and syndication agent (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed November 23, 2005).

10.16 Amendment No. 1 to Second Amended and Restated Credit Agreement dated as of December 22, 2005, among PetroQuest Energy, LLC, PetroQuest Energy, Inc., Pittrans, Inc., TDC Energy LLC, JP Morgan Chase Bank, N.A. as lender, agent and issuer of letters of credit, Macquarie Bank Limited as lender, and Calyon New York Branch as lender and syndication agent (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed December 22, 2005).

10.17 Amendment No. 2 to Second Amended and Restated Credit Agreement dated as of November 16, 2006 among PetroQuest Energy, LLC, PetroQuest Energy, Inc., Pittrans, Inc., TDC Energy LLC, JP Morgan Chase Bank, N.A. as lender, agent and issuer of letters of credit, Macquarie Bank Limited as lender, and Calyon New York Branch as lender and syndication agent (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed November 21, 2006).

10.18 Amendment No. 3 to Second Amended and Restated Credit Agreement dated as of September 17, 2007 among PetroQuest Energy, LLC, PetroQuest Energy, Inc., Pittrans, Inc., TDC Energy LLC, JP Morgan Chase Bank, N.A. as lender, agent and issuer of letters of credit, Macquarie Bank Limited as lender, and Calyon New York Branch as lender and syndication agent (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed September 18, 2007).

10.19 Amendment No. 4 to Second Amended and Restated Credit Agreement dated as of September 19, 2007 among PetroQuest Energy, LLC, PetroQuest Energy, Inc., Pittrans, Inc., TDC Energy LLC, JP Morgan Chase Bank, N.A. as lender, agent and issuer of letters of credit, Macquarie Bank Limited as lender, and Calyon New York Branch as lender and syndication agent (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed September 24, 2007).

10.20 Senior Second Lien Secured Credit Agreement dated November 6, 2003, between PetroQuest Energy, L.L.C., PetroQuest Energy, Inc., each of the Lenders from time to time party thereto; and Macquarie Americas Corp., as administrative agent for the Lenders (incorporated herein by reference to Exhibit 10.1 to Form 10-Q filed November 13, 2003).

10.21 Unconditional Guaranty Agreement dated November 6, 2003, by PetroQuest Energy, Inc. to Macquarie Americas Corp., as administrative agent for the benefit of the Lenders under the Credit Agreement (incorporated herein by reference to Exhibit 10.2 to Form 10-Q filed November 13, 2003).

10.22 First Amendment to Second Lien Secured Credit Agreement dated December 23, 2003, among PetroQuest Energy, L.L.C., PetroQuest Energy, Inc., each of the Lenders from time to time party thereto, and Macquarie Americas Corp., as administrative agent for the Lenders (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed December 29, 2003).

10.23 Second Amendment to Second Lien Secured Credit Agreement dated July 27, 2004, among PetroQuest Energy, L.L.C., PetroQuest Energy, Inc., each of the Lenders from time to time party thereto, and Macquarie Americas Corp., as administrative agent for the Lenders (incorporated herein by reference to Exhibit 10.2 to Form 10-Q filed July 30, 2004).

10.24 Third Amendment to Second Lien Secured Credit Agreement dated as of October 14, 2004 by and between PetroQuest Energy, LLC, PetroQuest Energy, Inc. and Macquarie Bank Limited (incorporated herein by reference to Exhibit 10.2 on Form 8-K filed October 19, 2004).

10.25 Fourth Amendment to Second Lien Secured Credit Agreement dated as of December 29, 2004 by and between PetroQuest Energy, LLC and Macquarie Bank Limited (incorporated herein by reference to Exhibit 10.1 on Form 8-K filed December 30, 2004).

10.26 Fifth Amendment to Second Lien Secured Credit Agreement dated April 12, 2005, among PetroQuest Energy, LLC, TDC Energy LLC f/k/a TDC Acquisition Sub LLC, PetroQuest Energy, Inc. and Macquarie Bank Limited (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed April 13, 2005).

† 10.27 Employment Agreement dated September 1, 1998, between PetroQuest Energy, Inc. and Charles T. Goodson (incorporated herein by reference to Exhibit 10.2 to Form 8-K dated September 16, 1998).

† 10.28 First Amendment to Employment agreement dated September 1, 1998 between PetroQuest Energy, Inc. and Charles T. Goodson dated July 30, 1999 (incorporated herein by reference to Exhibit 10.1 to For 8-K dated August 9, 1999).

† 10.29 Severance Agreement and Release, effective April 8, 2005, between PetroQuest Energy, Inc. and Ralph J. Daigle (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed April 22, 2005).

† 10.30 Employment Agreement dated May 8, 2000 between PetroQuest Energy, Inc. and Michael O. Aldridge (incorporated herein by reference to Exhibit 10.1 to the Form 10-Q filed August 14, 2000).

† 10.31 Employment Agreement dated December 15, 2000 between PetroQuest Energy, Inc. and Arthur M. Mixon, III. (incorporated herein by reference to Exhibit 10.12 to Form 10-K filed March 30, 2001).

† 10.32 Employment Agreement dated April 20, 2001 between PetroQuest Energy, Inc. and Daniel G. Fournerat (incorporated herein by reference to Exhibit 10.1 to Form 10-Q filed May 15, 2001).

† 10.33 Employment Agreement dated April 20, 2001 between PetroQuest Energy, Inc. and Dalton F. Smith III (incorporated herein by reference to Exhibit 10.21 to Form 10-K filed March 13, 2002).

† 10.34 Employment Agreement dated July 28, 2003, between PetroQuest Energy, Inc. and Stephen H. Green (incorporated herein by reference to Exhibit 10.3 to Form 10-Q filed November 13, 2003).

† 10.35 Form of Termination Agreement Between PetroQuest Energy, Inc. and each of its executive officers, including Charles T. Goodson, Michael O. Aldridge, Arthur M. Mixon, III, Daniel G. Fournerat, Dalton F. Smith III and Stephen H. Green (incorporated herein by reference to Exhibit 10.20 to Form 10-K filed March 13, 2002).

† 10.36 Form of Amendment to Termination Agreement entered into between the Company and each of its executive officers (including Charles T. Goodson, Michael O. Aldridge, Arthur M. Mixon, III, Daniel G. Fournerat and Stephen H. Green), effective as of May 16, 2006 (incorporated herein by reference to Exhibit 10.4 to Form 8-K filed May 19, 2006).

† 10.37 Form of Indemnification Agreement between PetroQuest Energy, Inc. and each of its directors and executive officers, including Charles T. Goodson, Daniel G. Fournerat, E. Wayne Nordberg, William W. Rucks, IV, Michael O. Aldridge, Arthur M. Mixon, III, Dalton F. Smith III, Michael L. Finch, W.J. Gordon, III, Stephen H. Green 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.

*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.

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* 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. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

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

Developmental well. A well drilled into a proved natural gas or oil 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 and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend 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 either 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.

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 developed non-producing reserves. Proved developed reserves expected to be recovered from zones behind casing in existing wells.

Proved developed producing reserves ("PDP"). Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production to market.

Proved developed reserves. Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

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

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

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

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.

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 29, 2008.

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 29, 2008.

By: /s/ Charles T. Goodson CHARLES T. GOODSON	Chairman of the Board, President, Chief Executive Officer and Director (Principal Executive Officer)
By: /s/ Michael O. Aldridge MICHAEL O. ALDRIDGE	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

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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, 2007 and 2006, and the related consolidated statements of income, stockholders' equity, cash flows and comprehensive income for each of the three years in the period ended December 31, 2007. 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, 2007 and 2006, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, in 2006 the Company changed its method of accounting for stock-based compensation.

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, 2007, 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 29, 2008 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
New Orleans, Louisiana
February 29, 2008

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

	December 31, 2007	December 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 16,909	$ 4,795
Revenue receivable	22,820	21,767
Joint interest billing receivable	22,936	20,072
Hedging asset	-	10,527
Prepaid drilling costs	1,448	4,886
Other current assets	3,984	2,143
Total current assets	68,097	64,190
Property and equipment:		
Oil and gas properties:		
Oil and gas properties, full cost method	907,083	695,116
Unevaluated oil and gas properties	80,297	51,567
Accumulated depreciation, depletion and amortization	(432,530)	(314,869)
Oil and gas properties, net	554,850	431,814
Gas gathering assets	22,040	19,072
Accumulated depreciation and amortization of gas gathering assets	(6,640)	(3,562)
Total property and equipment	570,250	447,324
Other assets, net of accumulated depreciation and amortization of $11,238 and $11,719, respectively	6,000	6,776
Total assets	$ 644,347	$ 518,290
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable to vendors	$ 78,273	$ 34,790
Advances from co-owners	12,870	13,391
Oil and gas revenue payable	5,771	6,935
Accrued interest and preferred stock dividend	3,320	2,453
Asset retirement obligation	5,280	9,028
Other accrued liabilities	6,326	5,484
Total current liabilities	111,840	72,081
Bank debt	-	47,000
10 3/8% Senior Notes	148,755	148,537
Asset retirement obligation	12,171	11,211
Deferred income taxes	69,160	49,646
Other liabilities	104	104
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $.001 par value; authorized 5,000 shares; issued and outstanding 1,495 and 0, respectively	1	-
Common stock, $.001 par value; authorized 75,000 shares; issued and outstanding 48,414 and 47,788 shares, respectively	48	48
Paid-in capital	204,979	124,552
Accumulated other comprehensive income (loss)	(435)	6,632
Retained earnings	97,724	58,479
Total stockholders' equity	302,317	189,711
Total liabilities and stockholders' equity	$ 644,347	$ 518,290

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
Consolidated Statements of Income
(Amounts in Thousands, Except Per Share Data)

	Year Ended December 31,		
	2007	2006	2005
Revenues:			
Oil and gas sales	$ 256,223	$ 193,861	$ 120,552
Gas gathering revenue and other income	7,451	6,683	4,042
	263,674	200,544	124,594
Expenses:			
Lease operating expenses	31,965	34,735	20,972
Production taxes	7,859	6,576	3,764
Depreciation, depletion and amortization	119,969	85,858	43,747
Gas gathering costs	4,120	3,637	1,246
General and administrative	21,162	15,122	7,347
Accretion of asset retirement obligation	923	1,513	1,253
Interest expense	13,393	14,513	12,371
	199,391	161,954	90,700
Income from operations	64,283	38,590	33,894
Income tax expense	23,664	14,604	12,477
Net income	40,619	23,986	21,417
Preferred stock dividend	1,374	-	-
Net income available to common stockholders	$ 39,245	$ 23,986	$ 21,417
Earnings per common share:			
Basic			
Net income per share	$ 0.82	$ 0.50	$ 0.46
Diluted			
Net income per share	$ 0.79	$ 0.49	$ 0.44
Weighted average number of common shares:			
Basic	48,108	47,537	46,714
Diluted	49,679	48,936	48,242

See accompanying Notes to Consolidated Financial Statements.

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

	Year Ended December 31, 2007	2006	2005
Cash flows from operating activities:			
Net income	$ 40,619	$ 23,986	$ 21,417
Adjustments to reconcile net income to net cash provided by operating activities:			
Deferred tax expense	23,664	14,604	12,477
Amortization of debt issuance costs	969	943	1,390
Compensation expense	-	-	213
Depreciation, depletion and amortization	119,969	85,858	43,747
Write-off of debt issuance costs	-	-	2,575
Amortization of bond discount	218	197	111
Share-based compensation expense	9,818	5,651	-
Accretion of asset retirement obligation	923	1,513	1,253
Payments to settle asset retirement obligations	(6,058)	(252)	-
Changes in working capital accounts:			
Revenue receivable	(1,053)	725	(13,100)
Joint interest billing receivable	(2,864)	(2,505)	(13,912)
Accounts payable and accrued liabilities	37,050	(13,552)	14,255
Other assets	(602)	(1,743)	(448)
Advances from co-owners	(521)	7,517	3,609
Other	1,597	(3,572)	(397)
Net cash provided by operating activities	223,729	119,370	73,190
Cash flows from investing activities:			
Investment in oil and gas properties	(233,436)	(175,277)	(171,980)
Sale of oil and gas properties	1,277	22,023	-
Investment in gas gathering assets	(2,968)	(6,363)	(10,861)
Net cash used in investing activities	(235,127)	(159,617)	(182,841)
Cash flows from financing activities:			
Net (payments for) proceeds from share based compensation	(99)	1,461	972
Proceeds from preferred stock offering	74,750	-	-
Costs of preferred stock offering	(4,041)	-	-
Proceeds from bank borrowings	23,000	48,000	44,500
Repayment of bank borrowings	(70,000)	(11,000)	(73,000)
Proceeds from issuance of 10 3/8% Senior Notes	-	-	148,229
Deferred financing costs	(98)	(122)	(5,876)
Net cash provided by financing activities	23,512	38,339	114,825
Net increase (decrease) in cash and cash equivalents	12,114	(1,908)	5,174
Cash and cash equivalents at beginning of period	4,795	6,703	1,529
Cash and cash equivalents at end of period	$ 16,909	$ 4,795	$ 6,703
Supplemental disclosure of cash flow information			
Cash paid during the period for:			
Interest	$ 19,238	$ 17,572	$ 9,628
Income taxes	$ -	$ -	$ 75

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	Total Stockholders' Equity
December 31, 2004	$ 45	$ -	$ 112,387	$ (4,231)	$ 13,076	$ 121,277
Options and warrants exercised	2	-	1,003	-	-	1,005
Issuance of common stock	-	-	4,051	-	-	4,051
Derivative fair value adjustment, net of tax	-	-	-	(3,213)	-	(3,213)
Net income	-	-	-	-	21,417	21,417
December 31, 2005	$ 47	$ -	$ 117,441	$ (7,444)	$ 34,493	$ 144,537
Options and warrants exercised	1	-	1,460	-	-	1,461
Share-based compensation expense	-	-	5,651	-	-	5,651
Derivative fair value adjustment, net of tax	-	-	-	14,076	-	14,076
Net income	-	-	-	-	23,986	23,986
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

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
Consolidated Statements of Comprehensive Income
(Amounts in Thousands)

	Year Ended December 31,		
	2007	2006	2005
Net income	$ 40,619	$ 23,986	$ 21,417
Change in fair value of derivative instruments, accounted for as hedges, net of tax benefit (expense) of $4,150, ($7,903) and $1,730, respectively	(7,067)	14,076	(3,213)
Comprehensive income	$ 33,552	$ 38,062	$ 18,204

See accompanying 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.

Oil and Gas Properties

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.

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 period-end oil and gas prices (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. In September 2004, the Securities and Exchange Commission adopted Staff Accounting Bulletin ("SAB") No. 106, regarding the application of 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. The Company began applying SAB No. 106 in the first quarter of 2005. Transactions involving sales of reserves in place, unless significant, are recorded as adjustments to accumulated depreciation, depletion and amortization.

Gas Gathering Assets

During 2005 the Company acquired interests in several gas gathering systems used in the transportation of natural gas. During 2007 and 2006, the Company expanded these systems in order to accommodate additional wells and increased production. The costs related to these systems are depreciated on a straight line basis over their estimated remaining useful lives, generally 14 years.

Other Assets

Other assets consist primarily of 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.

Cash and Cash Equivalents

The Company considers all highly liquid investments in overnight securities made through its commercial bank accounts, which result in available funds the next business day, to be cash and cash equivalents.

Income Taxes

The Company accounts for income taxes in accordance with Statement of Financial Accounting Standards (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 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, 2007 and 2006 were not significant.

Certain Concentrations

Our production is sold on month to month contracts at prevailing prices. We attempt to diversify our sales and obtain credit protection such as letters of credit and parental guarantees when necessary. The following table identifies customers from whom we derived 10% or more of our 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,		
	2007	2006	2005
DCP Midstream	12%	(a)	(a)
Cokinos	(a)	11%	12%
Louis Dreyfus Corporation	16%	12%	20%
Texon LP	32%	22%	16%
Crosstex	(a)	14%	(a)

(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, 2007 and 2006 due to the short-term nature of these accounts. The fair value of the bank debt at December 31, 2006 also approximated book value due to the variable rate of interest charged. Hedging instruments are reflected as assets (liabilities) on the balance sheet at estimated fair values of approximately ($0.7) million and $10.5 million at December 31, 2007 and 2006, respectively, as required under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities". These estimated fair values are based on quotes obtained from counterparties as discussed below. The estimated fair value of the 10 3/8% senior notes due 2012 (the "Notes") at December 31, 2007 was $154.5 million, as compared to the book value, net of discount, of $148.8 million. At December 31, 2006, the fair value of the Notes was $156.4 million, while the book value of the Notes, net of discount, was $148.5 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 SFAS No. 133, as amended, the nature of a derivative instrument must be evaluated to determine if it qualifies for hedge accounting treatment. Instruments qualifying for hedge accounting treatment are recorded as an asset or liability measured at fair value and subsequent changes in fair value are recognized in equity through other comprehensive income, net of related taxes, to the extent the hedge is effective. All of the Company's derivative instruments qualified for hedge accounting during 2007, 2006 and 2005. As a result, the changes in fair value of these instruments were recorded to other comprehensive income. The cash settlements of cash flow hedges are recorded as adjustments to oil and gas sales. Instruments not qualifying for hedge accounting treatment are recorded in 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, 2007, the Company's hedging contracts were considered effective cash flow hedges.

Estimating the fair value of hedging derivatives requires complex calculations incorporating estimates of future prices, discount rates and price movements. As a result, the Company obtains the fair value of its commodity derivatives from the counterparties to those contracts. Because the counterparties are market makers, they are able to provide a market value, or what they would be willing to settle such contracts for as of the given date.

Oil and gas revenues include additions (reductions) related to the net settlement of hedges totaling $9,922,000, $6,849,000 and ($15,814,000) during 2007, 2006 and 2005, respectively.

As of December 31, 2007, the Company had entered into the following oil and gas hedge contracts accounted for as cash flow hedges:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
2008	Costless Collar	20,000 Mmbtu	$7.75 - 8.78
Crude Oil:			
2008	Costless Collar	400 Bbls	$70.00 - 75.55

At December 31, 2007, the Company recognized a liability of $0.7 million related to the estimated fair value of these derivative instruments. Based on estimated future commodity prices as of December 31, 2007, the Company would realize a $0.4 million loss, net of taxes, as a reduction to oil and gas sales during the next 12 months. These losses are expected to be reclassified based on the schedule of oil and gas volumes stipulated in the derivative contracts.

In January and February 2008, the Company entered into the following oil and gas hedge contracts accounted for as cash flow hedges:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
February-December 2008	Costless Collar	7,500 Mmbtu	$7.50 - 8.98
March-June 2008	Costless Collar	10,000 Mmbtu	$8.25 - 8.75
April-December 2008	Costless Collar	7,500 Mmbtu	$9.00 - 10.35
Crude Oil:			
February-June 2008	Costless Collar	400 Bbls	$85.00 - 115.00

New Accounting Standards

In June 2006, the Financial Accounting Standards Board (the "FASB") issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" ("FIN 48"). FIN 48 is an interpretation of SFAS 109 and it seeks to reduce the diversity in practice associated with certain aspects of measurement and accounting for income taxes and requires expanded disclosure with respect to the uncertainty in income taxes. FIN 48 is effective for fiscal years beginning after December 15,

2006. Accordingly, the Company adopted FIN 48 on January 1, 2007. The adoption of FIN 48 did not have an effect on the Company's financial position or results of operations. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of the date of adoption and December 31, 2007, the Company did not have any unrecognized tax benefits or accrued interest or penalties related to uncertain tax positions. The tax years from 2002 through 2006 remain open to examination by the tax jurisdictions to which the Company is subject.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" ("SFAS No. 157"). SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosure about fair value measurements. SFAS No. 157 will be effective for financial statements issued for fiscal years beginning after November 15, 2007. In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Liabilities – Including an amendment of FASB Statement No. 115" ("SFAS No. 159"). SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value. This statement became effective for the Company on January 1, 2008. The Company is evaluating these standards and does not anticipate that their implementation will have a material effect on its financial statements.

Note 2 Convertible Preferred Stock

During September and October 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 net proceeds received from the offering were primarily used to repay the $58,000,000 of outstanding borrowings under the Company's credit facility. Details of the offering are as follows:

	Preferred Stock Offering
Gross proceeds	$ 74,750,000
Underwriting discount	(3,737,500)
Other costs of the offering	(303,480)
Net proceeds	$ 70,709,020
Shares issued	1,495,000
Issue price per share	$ 50.00

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. The first dividend payment of $1,584,700 was made on January 15, 2008.

Subject to certain limited exceptions, no dividends or other distributions (other than a dividend payable solely in shares of a like or junior ranking) may be paid or set apart for payment upon any shares ranking equally with the Series B Preferred Stock ("parity shares") or shares ranking junior to the Series B Preferred Stock ("junior shares"), nor may any parity shares or junior shares be redeemed or acquired for any consideration by the Company (except by conversion into or exchange for shares of a like or junior ranking) unless all accumulated and unpaid dividends have been paid or funds therefore have been set apart on the Series B Preferred Stock and any parity shares.

Liquidation preference. In the event of the Company's voluntary or involuntary liquidation, winding-up or dissolution, each holder of Series B Preferred Stock will be entitled to receive and to be paid out of the Company's assets available for distribution to the Company's stockholders, before any payment or distribution is made to holders of junior stock (including common stock), but after any distribution on any of the Company's indebtedness or senior stock, a liquidation preference in the amount of $50 per share of the Series B Preferred Stock, plus accumulated and unpaid dividends on the shares to the date fixed for liquidation, winding-up or dissolution.

Ranking. The Series B Preferred Stock will rank:

- senior to all of the shares of the Company's common stock and to all of the Company's other capital stock issued in the future unless the terms of such capital stock expressly provide that it ranks senior to, or on a parity with, shares of the

Series B Preferred Stock;

- on a parity with all of the Company's other capital stock issued in the future the terms of which expressly provide that it will rank on a parity with the shares of the Series B Preferred Stock; and
- junior to all of the Company's existing and future debt obligations and to all shares of the Company's capital stock issued in the future the terms of which expressly provide that such shares will rank senior to the shares of the Series B Preferred Stock.

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.

Limited optional redemption. If fewer than 15% of the shares of Series B Preferred Stock are outstanding, the Company may, at any time on or after October 20, 2010, at its option, redeem for cash all such Series B Preferred Stock at a redemption price equal to the liquidation preference of $50 plus any accrued and unpaid dividends, if any, on a share of Series B Preferred Stock to, but excluding, the redemption date, for each share of Series B Preferred Stock.

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.

Purchase or exchange upon fundamental change. If the Company becomes subject to a fundamental change (as defined below), each holder of shares of Series B Preferred Stock will have the right to require the Company to purchase any or all of its shares at a purchase price equal to 100% of the liquidation preference, plus accumulated and unpaid dividends, to the date of the purchase. The Company will have the option to pay the purchase price in cash, shares of common stock or a combination of cash and shares. If the Company chooses to pay all or a portion of the purchase price in shares of common stock, in no event will the total number of shares of common stock issuable upon repurchase exceed 11.1857 shares of common stock for each share of Series B Preferred Stock, subject to adjustment, and the Company will not be required to pay cash in the event the per share value of the common stock issued upon any such repurchase is less than the common stock value floor; *provided, however,* that the Company shall not pay the purchase price in shares of common stock or a combination of shares of common stock and cash unless (1) the Company shall have given a timely fundamental change notice including its intention to pay the purchase price or a specified percentage of the purchase price with shares of common stock and (2) such shares of common stock are registered under the Securities Act and the Exchange Act, in each case. The Company's ability to purchase all or a portion of Series B Preferred Stock for cash is subject to the Company's obligation to repay or repurchase any outstanding debt required to be repaid or repurchased in connection with a fundamental change and to any contractual restrictions then contained in the Company's existing borrowing agreements.

Conversion in connection with a fundamental change. If a holder elects to convert its shares of Series B Preferred Stock in connection with certain fundamental changes, the Company will in certain circumstances increase the conversion rate for the Series B Preferred Stock. Upon a conversion in connection with a fundamental change, the holder will be entitled to receive a cash payment for all accumulated and unpaid dividends.

A "fundamental change" will be deemed to have occurred upon the occurrence of any of the following:

1. any "person" becomes the "beneficial owner" directly or indirectly, of more than 50% of the voting power of the Company's common equity;

2. individuals who on September 25, 2007, constituted the board of directors (together with any new directors whose election by such board of directors or whose nomination for election by the stockholders of the Company was approved by a vote of a majority of the directors of the Company then still in office who were either directors on September 25, 2007, or whose election or nomination for election was previously so approved) cease for any reason to constitute a majority of the board of directors then in office;

3. the merger or consolidation of the Company with or into another person or the merger of another person with or into the Company, or the sale of all or substantially all the assets of the Company to another person other than a transaction following which holders of securities that represented 100% of the voting power of the Company's common equity immediately prior to such transaction (or other securities into which such securities are converted as part of such merger or consolidation transaction) own directly or indirectly at least a majority of the voting power of the voting equity of the surviving person in such merger or consolidation transaction or transferee in such sale of assets transaction immediately after such transaction;

4. the adoption of a plan relating to the liquidation or dissolution of the Company; or

5. the Company's common stock is neither listed on a national securities exchange nor listed nor approved for quotation on an over-the-counter market in the United States.

However, a fundamental change will not be deemed to have occurred in the case of a share exchange, merger or consolidation or in an exchange offer having the result described in subsection 1 above, if 90% or more of the consideration in the aggregate paid for common stock (and cash payments pursuant to dissenters' appraisal rights) in the share exchange, merger or consolidation or exchange offer consists of common stock of a United States company traded on a national securities exchange (or which will be so traded or quoted when issued or exchanged in connection with such transaction).

Voting rights. If the Company fails to pay dividends for six quarterly dividend periods (whether or not consecutive) or if the Company fails to pay the purchase price on the purchase date for the Series B Preferred Stock following a fundamental change, holders of the Series B Preferred Stock will have voting rights to elect two directors to the Company's board.

In addition, subject to certain exceptions, the Company may generally not, without the approval of the holders of at least 66 2/3% of the shares of the Series B Preferred Stock then outstanding:

- amend the Company's certificate of incorporation and bylaws, by merger or otherwise, if the amendment would alter or change the powers, preferences, privileges or rights of the holders of shares of the Series B Preferred Stock so as to adversely affect them;

- issue, authorize or increase the authorized amount of, or issue or authorize any obligation or security convertible into or evidencing a right to purchase, any senior stock; or

- reclassify any of the Company's authorized stock into any senior stock of any class, or any obligation or security convertible into or evidencing a right to purchase any senior stock.

In addition, if the Company creates an additional series of preferred stock that is part of the same class as the Series B Preferred Stock and all series of the class are not equally affected by a proposed change, the approval of the holders of at least 66 2/3% of the series that would have diminished status will be required to amend the Company's certificate of incorporation and bylaws, by merger or otherwise.

Note 3 – Earnings Per Share

Basic earnings per common share is computed by dividing net income available to common stockholders by the weighted average number of shares of common stock outstanding during the periods presented. Diluted earnings per common share is determined on a weighted average basis using common shares issued and outstanding adjusted for the effect of stock options and restricted stock considered dilutive computed using the treasury stock method.

Diluted earnings per share for 2007 also considers the effect of the Series B Preferred Stock issued in September and October 2007 (Note 2) by applying the "if converted" method. Under this method, the dividends applicable to the Series B Preferred Stock are added back to the numerator and the Series B Preferred Stock is assumed to have been converted to common shares in the denominator at of the date of issuance. In applying the "if converted" method for the Series B Preferred Stock, conversion is not assumed in computing diluted earnings per share if the effect would be anti-dilutive.

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

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	$ 0.82
Effect of dilutive securities:			
Stock options	-	1,056	
Restricted stock	-	515	
Series B preferred stock	-	-	
DILUTED EPS	$ 39,245	49,679	$ 0.79

For the Year Ended December 31, 2006	Income (Numerator)	Shares (Denominator)	Per Share Amount
BASIC EPS			
Net income available to common stockholders	$ 23,986	47,537	$ 0.50
Effect of dilutive securities:			
Stock options	-	1,278	
Restricted stock	-	121	
DILUTED EPS	$ 23,986	48,936	$ 0.49

For the Year Ended December 31, 2005	Income (Numerator)	Shares (Denominator)	Per Share Amount
BASIC EPS			
Net income available to common stockholders	$ 21,417	46,714	$ 0.46
Effect of dilutive securities:			
Stock options	-	1,327	
Warrants	-	201	
DILUTED EPS	$ 21,417	48,242	$ 0.44

Options to purchase 155,000 shares of common stock at $13.35 to $14.48 per share were outstanding during 2007 but were not included in the computation of diluted earnings per share because the options' exercise prices were greater than the average market price of the common shares. These options expire during 2017. Options to purchase 153,000 shares of common stock at $11.29 to $12.54 per share were outstanding during 2006 but were not included in the computation of diluted earnings per share because the options' exercise prices were greater than the average market price of the common shares. Options to purchase 45,000 shares of common stock at $6.64 to $7.65 per share were outstanding during 2005 but were not included in the computation of diluted earnings per share because the options' exercise prices were greater than the average market price of the common shares. Additionally, diluted earnings per share during 2007 did not include the assumed conversion of the Series B Preferred Stock as the effect of assuming conversion was anti-dilutive.

In February 2005, the Company's then outstanding warrants were exercised through a cashless exercise provision, resulting in the issuance of 1,506,466 shares of common stock. The Company had no warrants outstanding as of December 31, 2007 or 2006.

Note 4 – Share Based Compensation

In December 2004, the FASB issued SFAS 123 (revised 2004), "Share Based Payment," which is a revision of SFAS 123, "Accounting for Stock-Based Compensation." SFAS 123(R) supersedes APB Opinion No. 25, "Accounting for Stock Issued to Employees," and amends SFAS 95, "Statement of Cash Flows." SFAS 123(R) requires all share-based payments to employees, including grants of employee stock options and restricted stock, to be recognized in the income statement based on their estimated fair values. Pro forma disclosure is no longer an alternative. The Company adopted the standard during the first quarter of 2006.

The Company elected to adopt SFAS 123(R) using the "modified prospective" method in which compensation cost is recognized beginning with the effective date of January 1, 2006 using the requirements of SFAS 123(R) for all share-based payments granted after the effective date and the requirements of SFAS 123 for all unvested awards at the effective date related to awards granted prior to the effective date. The impact to net income of adopting SFAS 123(R) for the year ended December 31, 2006 was $3.7 million, or approximately $0.08 per basic and diluted share. Prior to the adoption of SFAS 123(R) on January 1, 2006, the Company accounted for its share based compensation plans under the principles prescribed by APB Opinion No. 25. Accordingly, no share based compensation cost is reflected in net income prior to January 1, 2006, as all options granted under the plan had an exercise price equal to the market value of the underlying common stock on the date of grant and no restricted stock had been granted.

The Company currently has one share based compensation plan from which the Company's compensation committee may grant any of the following types of awards:

- incentive stock options as defined in Section 422 of the Code;
- nonstatutory stock options;
- stock appreciation rights;
- shares of restricted stock;
- performance units and performance shares;
- other stock-based awards; and
- supplemental payments dedicated to the payment of income taxes.

The total amount of share-based awards available for grant under the plan is equal to the greater of (i) 15% of the number of issued and outstanding shares of the Company's common stock as of the first day of the then-current fiscal quarter, or (ii) 7,000,000 shares.

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, 2007 and 2006 is as follows (in thousands):

	Years Ended December 31, 2007	Years Ended December 31, 2006
Stock options:		
Incentive Stock Options	$ 1,250	$ 526
Non-Qualified Stock Options	1,869	1,344
Restricted stock	6,699	3,781
Share based compensation	$ 9,818	$ 5,651

During the years ended December 31, 2007 and 2006, the Company recorded income tax benefits of $3.2 million and $1.9 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 substantial net operating losses available to carryover to future periods. Accordingly, no excess tax benefits have been recognized for any periods presented.

At December 31, 2007, the Company had $9.7 million of unrecognized compensation expense related to granted, but unvested restricted stock and stock options. This expense will be recognized over a weighted average period of approximately 1.2 years from December 31, 2007.

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 based on historical activity, an expected term of six years, using the simplified method prescribed in SAB 107 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 2007, 2006 and 2005:

	Years Ended December 31,		
	2007	2006	2005
Dividend yield	0%	0%	0%
Expected volatility	55.7% - 58.5%	59.0% - 62.8%	60.9% - 64.5%
Risk-free rate	4.0% - 5.1%	4.4% - 5.1%	3.8% - 4.6%
Expected term	6 years	6 years	5 years
Forfeiture rate	5.0%	8.4%	0%
Stock options granted (1)	440,676	679,189	155,000
Wgtd. avg. grant date fair value per share	$ 7.29	$ 6.69	$ 3.59
Fair value of grants (1)	$ 3,212,000	$ 4,543,000	$ 556,350

(1) Prior to applying estimated forfeiture rate

The following table details stock option activity during the year ended December 31, 2007:

	Number of Options	Wgtd. Avg. Exercise Price	Wgtd. Avg. Remaining Life	Aggregate Intrinsic Value (000's)
Outstanding at beginning of year	2,520,811	$5.18		
Granted	440,676	12.43		
Expired/cancelled/forfeited	(30,000)	10.59		
Exercised	(350,786)	3.00		
Outstanding at end of year	2,580,701	6.65	6.7 years	$19,738
Options exercisable at end of year	1,658,798	$4.01	5.5 years	$17,061
Options expected to vest	875,807	11.40	8.8 years	$2,542

The intrinsic value of options exercised during 2007, 2006 and 2005 totaled approximately $3.5 million, $3.8 million and $2.5 million, respectively.

The following table summarizes information regarding stock options outstanding at December 31, 2007:

Range of Exercise Price	Options Outstanding 12/31/07	Wgtd. Avg. Remaining Contractual Life	Wgtd. Avg. Exercise Price	Options Exercisable 12/31/07	Wgtd. Avg. Exercise Price
$0.85 - $3.00	403,967	2.9 years	$1.61	403,967	$1.61
$3.01 - $6.00	1,028,999	5.9 years	$3.44	1,002,330	$3.39
$6.01 - $10.75	573,900	8.2 years	$10.37	208,114	$10.08
$10.76 - $14.48	573,835	9.1 years	$12.24	44,387	$11.60
	2,580,701	6.7 years	$6.65	1,658,798	$4.01

Restricted Stock

During 2006, the Company began granting shares of restricted stock in connection with its share based compensation plan. 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, assuming a 5.0% 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 2007:

	Number of Shares	Wgtd. Avg. Fair Value per Share
Outstanding at beginning of year	1,409,895	$11.04
Granted	243,420	11.78
Expired/cancelled/forfeited	(5,456)	11.48
Lapse of restrictions	(362,405)	10.98
Outstanding at December 31, 2007 (1)	1,285,454	$11.18

(1) At December 31, 2007, the weighted average remaining life of restricted stock outstanding was 3.6 years.

The following table illustrates the pro forma effect on net income and earnings per share for the period presented prior to the adoption of SFAS 123(R), if the Company had applied the fair value recognition provisions of SFAS No. 123, pursuant to the disclosure requirements of SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure" (in thousands, except per share data):

	Year Ended December 31, 2005	
Net income	$	21,417
Stock-based compensation:		
Add: expense included in reported results, net of tax		22
Deduct: fair value based method, net of tax		(688)
Pro forma net income	$	20,751
Earnings per common share		
Basic - as reported	$	0.46
Basic - pro forma	$	0.44
Diluted - as reported	$	0.44
Diluted - pro forma	$	0.43

Note 5 – Asset Retirement Obligations

The Company accounts for its asset retirement obligations in accordance with SFAS No. 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. Retirement obligations associated with long-lived assets included within the scope of SFAS 143 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 the changes to the Company's asset retirement obligation liability (in thousands):

Asset retirement obligation at January 1, 2007	$	20,239
Liabilities incurred during 2007		585
Liabilities settled during 2007		(6,058)
Accretion expense		923
Revisions in estimates		1,762
Asset retirement obligation at December 31, 2007		17,451
Less: current portion of asset retirement obligation		(5,280)
Long-term asset retirement obligation	$	12,171

Note 6 - 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 subsidiaries not guaranteeing the Notes constituted less than 3% of the Company's consolidated assets and revenues at and for the years ended December 31, 2007, 2006 and 2005.

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, 2007, $1.9 million had been accrued in connection with the May 15, 2008 interest payment and the Company was in compliance with all of the covenants under the Notes.

On November 18, 2005, the Company and its wholly owned subsidiary, PetroQuest Energy, L.L.C., entered into the Second Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A., as lender, agent and issuer of letters of credit, Macquarie Bank Limited, as lender, and Calyon New York Branch, as lender and syndication agent. The credit agreement provides for a $100 million revolving credit facility that permits borrowings from time to time based on the available borrowing base as determined in the credit facility. The credit facility also allows for the use of up to $15 million of the borrowing base for letters of credit. The credit facility matures on November 19, 2009.

The credit facility is secured by, among other things, a lien on at least 90% of the PDP present value and at least 80% of the aggregate proved reserves of the Company's oil and gas properties. PDP present value means the present value discounted at nine percent of the future net revenues attributable to producing reserves. The borrowing base under the credit facility is based primarily upon the bi-annual valuation of the Company's mortgaged oil and gas properties. The borrowing base is currently $80 million and the next scheduled borrowing base re-determination will be on April 1, 2008 and the Company or the lenders may request additional borrowing base re-determinations. As of December 31, 2007, there were no borrowings outstanding under the credit facility and the Company was in compliance with all of the covenants therein.

Outstanding balances on the credit facility bear interest at either the alternate base rate plus a margin (based on a sliding scale of 0.125% to 0.875% based on borrowing base usage) or the Eurodollar rate plus a margin (based on a sliding scale of 1.375% to 2.125% depending on borrowing base usage). The alternate base rate is equal to the higher of the JPMorgan Chase prime rate or the Federal Funds Effective Rate plus 0.5% per annum, and the Eurodollar rate is equal to the applicable British Bankers' Association LIBOR rate for deposits in U.S. dollars.

The Company is subject to certain restrictive financial covenants under the credit facility, including a maximum ratio of consolidated indebtedness to annualized consolidated EBITDA, determined on a rolling four quarter basis, of 3.0 to 1 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 facility also includes customary restrictions with respect to liens, indebtedness, loans and investments, material changes in the Company's business, asset sales or leases or transfers of assets, restricted payments such as distributions and dividends, mergers or consolidations, transactions with affiliates and rate management transactions.

Note 7 - 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, one of the Company's directors, is a working interest owner 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 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. During the year ended December 31, 2006, revenues, net of costs were disbursed to Messrs. Goodson, Green and Stover, or their affiliates, in the amounts of $253,400, $896,200 and $98,900, respectively, and with respect to the working interests of Mr. Nordberg, revenues exceeded costs by $55,000. During the year ended December 31, 2005, revenues, net of costs were disbursed to Messrs. Goodson, Green and Stover, or their affiliates, in the amounts of $313,729, $254,367 and $59,700, respectively, and with respect to the working interests of Mr. Nordberg, revenues exceeded costs by $20,010. 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 2007.

Periodically, the Company charters private aircraft for business purposes. During 2007, the Company paid approximately $170,000 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. This amount represents the cost of the hours purchased by Mr. Goodson and totals approximately 50% of the Company's cost of chartering private aircraft during 2007. 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.

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, 2007, the Company's joint interest billing receivable included approximately $30,900 from related parties attributable to their share of costs. This represents less than 1% of the Company's total joint interest billing receivable at December 31, 2007.

Note 8 - 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,		
	2007	2006	2005
Acquisition costs:			
Proved	$ 1,253	$ 7,515	$ 58,121
Unproved	32,833	12,744	24,152
Exploration costs:			
Proved	104,669	70,526	39,311
Unproved	15,908	7,457	15,098
Development costs	71,973	61,643	51,420
Capitalized general and administrative and interest costs	14,061	10,841	7,719
Total costs incurred	$ 240,697	$ 170,726	$ 195,821

	For the Year-Ended December 31,		
Accumulated depreciation, depletion and amortization (DD&A)	2007	2006	2005
Balance, beginning of year	$ (314,869)	$ (210,774)	$ (168,453)
Provision for DD&A	(116,384)	(82,928)	(42,513)
Sale of proved properties and other	(1,277)	(21,167)	192
Balance, end of year	$ (432,530)	$ (314,869)	$ (210,774)
DD&A per Mcfe	$ 3.70	$ 3.23	$ 2.65

At December 31, 2007 and 2006, unevaluated oil and gas properties totaled $80,297,000 and $51,567,000, respectively, and were not subject to depletion. Unevaluated costs at December 31, 2007 included $15,908,000 of costs related to 12 exploratory wells in progress at year-end. The Company capitalized $6,539,000 and $4,650,000 of interest during 2007 and 2006, respectively. Of the total unevaluated oil and gas property costs at December 31, 2007, $55,281,000, or 69%, was incurred in 2007, $14,842,000 was incurred in 2006 and $10,174,000 was incurred in prior years. Management expects that the majority of the unevaluated costs at December 31, 2007 will be evaluated within the next three years.

Note 9 - Income Taxes

The Company follows the provisions of SFAS No. 109, "Accounting For Income Taxes," which provides for recognition of a deferred tax asset 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.

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

	December 31, 2007	December 31, 2006
Net operating loss carryforwards	$ 31,542	$ 28,331
Percentage depletion carryforward	2,928	2,068
Alternative minimum tax credit	105	105
Contributions carryforward and other	109	-
Temporary differences:		
Oil and gas properties - full cost	(104,252)	(76,408)
Hedges	255	(3,895)
Compensation expense	153	153
Deferred tax liability	$ (69,160)	$ (49,646)

For tax reporting purposes, the Company had operating loss carryforwards of $84,789,000 and $76,158,000 at December 31, 2007 and 2006, respectively. If not utilized, approximately $1,500,000 of such carryforwards would expire in 2008 and the remainder would completely expire by the year 2027. The Company has available for tax reporting purposes $8,368,000 in statutory depletion deductions that may be carried forward indefinitely.

Income tax expense for each of the years ended December 31, 2007, 2006 and 2005 (amounts in thousands) was different than the amount computed using the Federal statutory rate (35%) for the following reasons:

	For the Year-Ended December 31, 2007	2006	2005
Amount computed using the statutory rate	$ 22,499	$ 13,507	$ 11,863
Increase (reduction) in taxes resulting from:			
State & local taxes	1,414	849	746
Percentage depletion carryforward	(860)	(74)	(155)
Non-deductible stock option expense (1)	462	195	-
Other	149	127	23
Income tax expense	$ 23,664	$ 14,604	$ 12,477

(1) Relates to compensation expense recognized on the vesting of Incentive Stock Options in connection with the adoption of SFAS 123(R) on January 1, 2006.

Note 10 - Commitments and Contingencies

The Company is a party to ongoing litigation in the normal course of business. 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.

Lease Commitments

The Company has operating leases for office space and equipment, which expire on various dates through 2012.

Future minimum lease commitments as of December 31, 2007 under these operating leases are as follows (in thousands):

2008	$	951
2009		909
2010		189
2011		71
2012		11
Thereafter		-
	$	2,131

From July 2003 through April 2006, the Company subleased office space to third parties. For the years ended December 31, 2006 and 2005, the Company received $28,000 and $79,000, respectively, relative to subleased office space. Total rent expense under operating leases, net of amounts received under sublease arrangements, was approximately $910,000, $752,000 and $768,000 in 2007, 2006 and 2005, respectively.

Note 11 - Oil and Gas Reserve Information - Unaudited

The Company's net proved oil and gas reserves at December 31, 2007 have been estimated by independent petroleum engineers in accordance with guidelines established by the Securities and Exchange Commission. Accordingly, the following reserve estimates are based upon existing economic and operating conditions at the respective dates.

The estimates of proved oil and gas reserves constitute quantities that the Company is reasonably certain of recovering in future years. 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.

During 2007, the Company increased its estimated proved reserves by 16%. This increase was primarily due to the Company's drilling success during the year, offset in part by a record year of production. In terms of discoveries, the most significant reserve additions were on the Company's Oklahoma properties where there were 33 gross wells drilled in 2007 with a 91% success rate. The increase in proved reserves through revisions during 2007 was primarily due to positive performance at the Ship Shoal 72 and Main Pass 74 fields, along with positive performance revisions on the Oklahoma properties. Overall, the Company had an 87% drilling success rate during 2007 on 87 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, 2004	3,714	79,069
Revisions of previous estimates	(29)	(8,315)
Extensions, discoveries and other additions	362	29,966
Purchase of producing properties	294	21,211
Sale of producing properties	(34)	(758)
Production	(665)	(12,058)
Proved reserves as of December 31, 2005	3,642	109,115
Revisions of previous estimates	(197)	2,744
Extensions, discoveries and other additions	773	34,498
Purchase of producing properties	-	-
Sale of producing properties	(792)	(6,676)
Production	(695)	(21,528)
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
Proved developed reserves		
As of December 31, 2005	2,891	73,250
As of December 31, 2006	2,528	81,487
As of December 31, 2007	2,070	95,639

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,		
	2007	2006	2005
Future cash flows	$ 1,155,236	$ 786,829	$ 1,157,283
Future production costs	(240,849)	(168,037)	(195,648)
Future development costs	(134,993)	(102,778)	(99,946)
Future income taxes	(143,683)	(70,615)	(213,222)
Future net cash flows	635,711	445,399	648,467
10% annual discount	(188,453)	(112,566)	(165,055)
Standardized measure of discounted future net cash flows	$ 447,258	$ 332,833	$ 483,412

Changes in Standardized Measure	Year Ended December 31,		
	2007	2006	2005
Standarized measure at beginning of year	$ 332,833	$ 483,412	$ 257,754
Sales and transfers of oil and gas produced, net of production costs	(206,477)	(152,550)	(95,816)
Changes in price, net of future production costs	153,961	(221,118)	164,071
Extensions and discoveries, net of future production and development costs	95,850	124,138	168,802
Changes in estimated future development costs, net of development costs incurred during this period	12,014	18,016	6,398
Revisions of quantity estimates	66,025	5,199	(47,025)
Accretion of discount	38,431	63,973	32,627
Net change in income taxes	(41,913)	104,841	(87,808)
Purchase of reserves in place	14,108	-	94,834
Sale of reserves in place	(9,293)	(70,765)	(1,352)
Changes in production rates (timing) and other	(8,281)	(22,313)	(9,073)
Standardized measure at end of year	$ 447,258	$ 332,833	$ 483,412

The weighted average prices of oil and gas used for the above tables at December 31, 2007, 2006 and 2005 were $96.83, $59.85 and $59.66 per barrel, respectively, and $6.52, $5.28 and $8.61 per Mcfe, respectively. The Company's cash flow amounts include a reduction for estimated plugging and abandonment costs that have also been reflected as a liability on the balance sheet at December 31, 2007 and 2006, in accordance with SFAS No. 143.

Note 12 – 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
2007:				
Revenues	$ 64,008	$ 66,760	$ 65,500	$ 67,406
Expenses	53,194	57,130	57,462	55,269
Net income	$ 10,814	$ 9,630	$ 8,038	$ 12,137
Earnings per share:				
Basic	$ 0.23	$ 0.20	$ 0.16	$ 0.23
Diluted	$ 0.22	$ 0.19	$ 0.16	$ 0.22
2006:				
Revenues	$ 48,358	$ 51,496	$ 55,086	$ 45,604
Expenses	39,209	43,514	48,542	45,293
Net income	$ 9,149	$ 7,982	$ 6,544	$ 311
Earnings per share:				
Basic	$ 0.19	$ 0.17	$ 0.14	$ 0.01
Diluted	$ 0.19	$ 0.16	$ 0.13	$ 0.01

Exhibit 21.1

Subsidiaries of PetroQuest Energy, Inc.

Name	Jurisdiction
PetroQuest Energy, L.L.C[1]	Louisiana
PetroQuest Oil and Gas, L.L.C[1]	Louisiana
TDC Energy LLC[1]	Louisiana
Pittrans, Inc.[2]	Oklahoma
CSP Pipeline, L.L.C.[3]	Louisiana
Sea Harvester Energy Development Company, L.L.C.[4]	Louisiana

[1] 100% owned by PetroQuest Energy, Inc.
[2] 100% owned by PetroQuest Energy, L.L.C.
[3] 89.968% owned by TDC Energy LLC
[4] 92% owned by TDC Energy LLC

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. 333-131955, 333-124746, 333-42520 and 333-89961 and Form S-8 Nos. 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 29, 2008, 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, 2007.

/s/ Ernst & Young LLP
New Orleans, Louisiana
February 29, 2008

Exhibit 23.2

Consent of Ryder Scott Company, L.P.

We hereby consent to the incorporation by reference in this Annual Report on Form 10-K prepared by PetroQuest Energy, Inc. (the "Company") for the year ending December 31, 2007, and to the incorporation by reference thereof into the Company's previously filed Registration Statements on Form S-3 (File Nos. 333-131955, 333-124746, 333-42520 and 333-89961) and Form S-8 (File Nos. 333-134161, 333-102758, 333-88846, 333-67578, 333-52700 and 333-65401), of information contained in our reports 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, 2007. We further consent to references to our firm under the headings "Risk Factors" and "Oil and Gas Reserves."

/s/ RYDER SCOTT COMPANY, L.P.
Houston, Texas
February 28, 2008

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 29, 2008

Exhibit 31.2

I, Michael O. Aldridge, 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/ Michael O. Aldridge
Michael O. Aldridge
Chief Financial Officer
February 29, 2008

Exhibit 32.1

Certification Pursuant to 18 U.S.C. Section 1350 As Adopted Pursuant to Section 906 of the Sarbames-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, 2007 (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 29, 2008

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 Sarbames-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, 2007 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Michael O. Aldridge, 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/ Michael O. Aldridge
Michael O. Aldridge
Chief Financial Officer
February 29, 2008

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.

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

Art M. Mixon
Executive Vice President—Exploration and Production

Mark K. Stover
Executive Vice President—Corporate Development

W. Todd Zehnder
Executive Vice President, Chief Financial Officer, and Treasurer

J. Bond Clement
Senior Vice President and Chief Accounting Officer

Stephen H. Green
Senior Vice President—Exploration

Dalton F. Smith III
Senior Vice President—Business Development

James S. Blair
Vice President—Business Development

Thomas P. Murphy
Vice President—Engineering

Corporate Address

PetroQuest Energy, Inc.
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

Onebane Law Firm
Lafayette, Louisiana 70502

Porter & Hedges, L.L.P.
Houston, Texas 77002

Annual Meeting

The Company's Annual Meeting of Stockholders will be held at 9:00 a.m. CDT on May 14, 2008, at the City Club at River Ranch at 221 Elysian Fields Drive, Lafayette, Louisiana 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, In

400 East Kaliste Saloom Road, Suite 6000
Lafayette, Louisiana 70508
Telephone: (337) 232-7028 Fax: (337) 232-00
www.petroquest.com

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