PE
12-31-03

PETROQUEST ENERGY, INC.

2003 ANNUAL REPORT

CONTENTS

Notice of Annual Meeting of Stockholders

The annual meeting of stockholders of PetroQuest Energy will be held on May 12, 2004, at 9 a.m. at the City Club at River Ranch, 221 Elysian Fields Drive, Lafayette, Louisiana 70508.

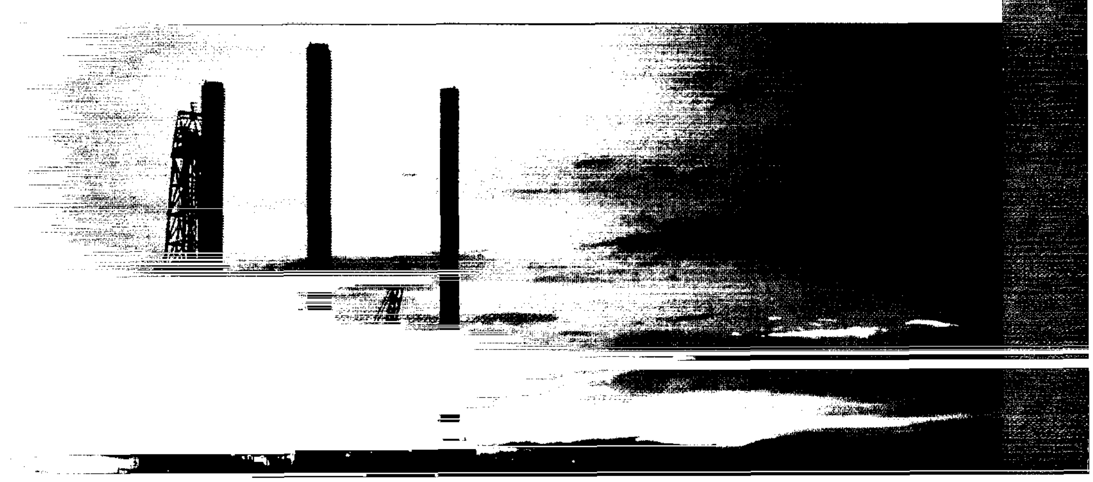
CORPORATE PROFILE

PetroQuest's acquisition, exploration and development operations are centered in one of America's largest producing regions – the onshore and offshore Gulf of Mexico and East Texas. This region delivers more than 25% of America's daily supply of oil and natural gas and is home to the Henry Hub, the world's most watched natural gas pricing point.

The Company's emphasis is on controlling the entire exploration model – from idea to cash flow. Since 1998, PetroQuest added 130 Bcfe of reserves through its drilling and acquisition activities, while producing 45 Bcfe, delivering a 289% production replacement ratio, a top-quartile performance.

PetroQuest's management team and staff are guided by four principles: generate our own exploration ideas; operate the majority of our total proved reserves; maintain a flexible balance sheet; and over-deliver on our promises.

PetroQuest Energy, Inc. and its 44 employees are based in Lafayette, Louisiana, the heart of America's Gulf Coast producing region. Collectively, management, employees and the board of directors own approximately 20% of PetroQuest's common stock. Approximately 650,000 of PetroQuest's common shares trade each day on the NASDAQ National Market System under the ticker PQUE. The Company's common shares are widely held with 27% owned by some of America's top institutional money managers.



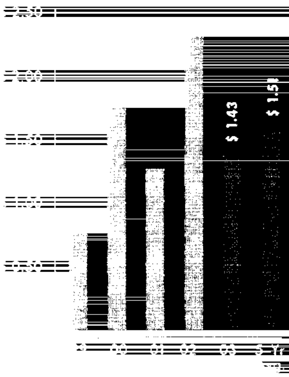
FINANCIAL & OPERATIONAL HIGHLIGHTS

Year-over-Year Review

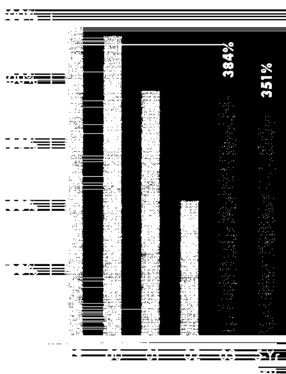
	1999	2000	2001	2002	2003	4-Year CAGR
Reserves						
Natural Gas, MMcf	15,128	30,135	44,944	37,137	57,793	40%
Crude Oil, MBbl	*2,194*	*3,115*	*6,213*	*5,258*	*4,245*	*18%*
Natural Gas, Bcfe	28,292	48,824	82,225	68,685	83,263	31%
Percent Developed	31%	67%	55%	62%	67%	nm
Percent Natural Gas	53%	62%	55%	54%	69%	nm
Percent Offshore	52%	57%	80%	84%	55%	nm
Future Gross Revenues, $ 000s	$ 92,788	$ 391,078	$ 234,736	$ 337,776	$ 460,073	49%
SEC PV-10, Before Taxes, $ 000s	*$ 43,069*	*$ 256,867*	*$ 88,230*	*$ 166,048*	*$ 214,365*	*49%*
Commodity Prices						
PetroQuest Realized, Natural Gas, $/Mcf	$ 2.33	$ 4.38	$ 3.86	$ 3.20	$ 5.14	
Henry Hub Cash Market Average, Natural Gas, $/Mcf	$ 2.27	$ 4.15	$ 3.96	$ 3.32	$ 5.49	Source: Bloomberg
PetroQuest Realized, Crude Oil, $/Bbl	*$ 18.45*	*$ 29.94*	*$ 25.49*	*$ 25.07*	*$ 28.47*	
WTI (Cushing) Spot Average, Crude Oil, $/Bbl	$ 19.30	$ 30.35	$ 25.84	$ 26.17	$ 31.06	Source: Bloomberg
PetroQuest Realized, Natural Gas Equivalent, $/Mcfe	$ 2.46	$ 4.50	$ 3.99	$ 3.61	$ 4.96	
Statistics						
Reserve Replacement, Excluding Revisions, %	*486%*	*473%*	*385%*	*211%*	*384%*	
5-Year Reserve Replacement, Excluding Revisions, %					351%	
Finding & Development Costs, Excluding Revisions, $/Mcfe	$ 0.77	$ 1.75	$ 1.27	$ 2.31	$ 1.43	
5-Year Finding & Development Costs, Excluding Revisions, $/Mcfe					$ 1.51	
Per Unit Analysis, $/Mcfe						
Revenues	$ 2.46	$ 4.51	$ 3.99	$ 3.61	$ 4.96	19%
Lease Operating Expense & Production Taxes	$ 0.88	$ 0.76	$ 0.60	$ 0.79	$ 1.07	5%
Gross Margin	$ 1.58	$ 3.75	$ 3.39	$ 2.82	$ 3.89	25%
DD&A	$ 1.29	$ 1.29	$ 1.68	$ 2.11	$ 2.81	21%
Net Income	$ (0.09)	$ 2.01	$ 0.85	$ 0.17	$ 0.38	nm

Growth

	1999 Annual	2000 Annual	2001 Annual	2002 Annual	2003 Q1	2003 Q2	2003 Q3	2003 Q4	2003 Annual	4-Year CAGR
Production										
Natural Gas, MMcf	*2,831*	*3,984*	*9,025*	*7,765*	*1,606*	*846*	*1,032*	*1,709*	*5,193*	*16%*
Crude Oil, MBbl	105	161	791	929	235	183	166	160	745	63%
Natural Gas, MMcfe	3,461	4,948	13,774	13,340	3,016	1,944	2,028	2,671	9,660	29%
$ 000s, except per share amounts										
Financial										
Total Revenues	$ 8,686	$ 22,561	$ 55,342	$ 48,238	$ 16,164	$ 9,101	$ 9,857	$ 13,566	$ 48,688	54%
Net Income / (Loss)	$ (310)	$ 9,924	$ 11,645	$ 2,307	$ 2,993	$ (1,698)	$ 229	$ 2,116	$ 3,640	nm
Per Common Share:										
Basic	$ (0.01)	$ 0.37	$ 0.37	$ 0.06	$ 0.07	$ (0.04)	$ 0.01	$ 0.05	$ 0.08	nm
Diluted	$ (0.01)	$ 0.35	$ 0.34	$ 0.06	$ 0.07	$ (0.04)	$ 0.01	$ 0.05	$ 0.08	nm



Finding & Development Costs, Excluding Revisions, $/Mcfe



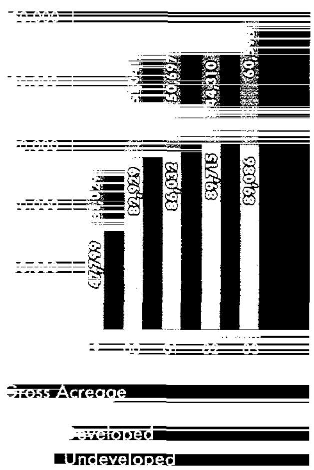
Reserve Replacement, Excluding Revisions

In a year of challenges, PetroQuest accomplished much in 2003. Both cash flow and earnings increased over 2002. In the second half of the year, we turned around the production decline experienced in the first half. We established a new core operating area in December with a $23 million acquisition of a producing property in East Texas. Company-wide total proved reserves reached 83.3 Bcfe. We replaced 251% of our 2003 production at an all sources finding cost of $2.19 per Mcfe. Since 1998, PetroQuest's drill bit and acquisition activities added 130 Bcfe of reserves and production was 45 Bcfe, a better than 2.8:1 ratio. Over the same period, reserves increased at a 31% compounded annual growth rate and production increased at a 29% compounded annual growth rate. In 2004, with our capital expenditure budget of $40 million to $45 million PetroQuest plans to drill 20 or more wells targeting an estimated gross unrisked reserve potential of 219 Bcfe.

Fundamental financial and operating improvements were made in 2003. PetroQuest reported net income of $0.08 per basic share, a 33% increase from 2002, and the fourth consecutive year of positive net income. We financed our acquisition of the Southeast Carthage Field with debt, yet maintained a healthy debt to book cap of 25% at December 31, 2003. Our 83.3 Bcfe of proved reserves have net present value discounted at 10% of $214.4 million on a pre-tax basis, a positive year-over-year change of 29%. This is a very solid financial and operating performance.

Moving Up

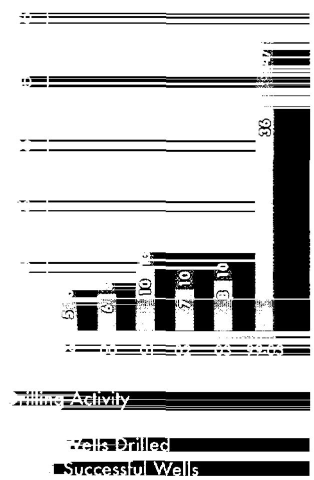
As I described the just finished year, 2003 was measurably better than 2002. The faith we placed in our people, ideals and core



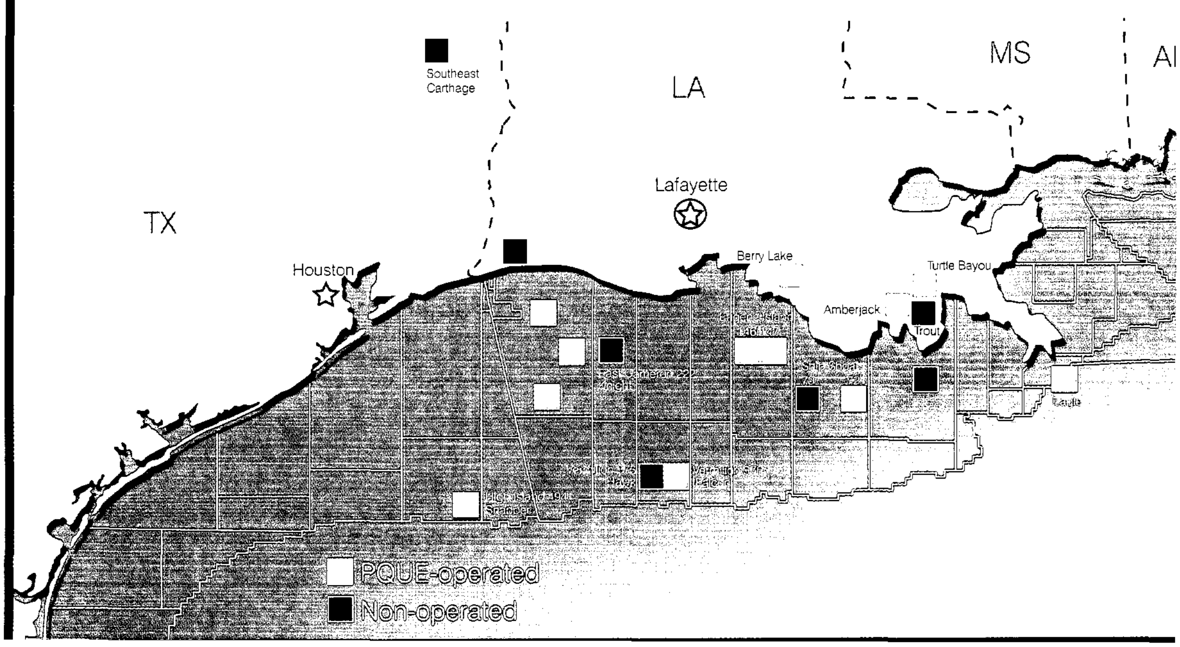
competencies enabled PetroQuest to move forward with our growth strategies in 2003. Our tenets of integrity, excellence and hard work will always prevail, regardless of market or industry conditions. Our core competencies have provided us with the competitive advantage to be successful. Staying the course as we have allowed us to work through a tough year. I have the utmost confidence 2004 will be markedly better than 2003.

Creating Value

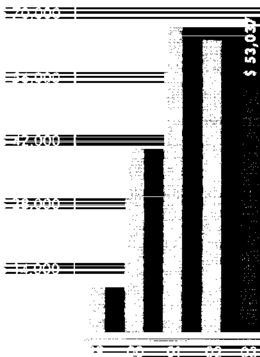
Exploration is a focal point of PetroQuest's growth strategy. Commodity prices being what they were in 2003, we were laser focused on increasing production. We overcame the unsuccessful wells drilled at the end of 2002 that put downward pressure on the early portion of 2003's production profile by putting capital to work drilling wells with higher probability for success. We began adding to our production base in the third quarter with our drilling successes. We forecast production will increase in 2004 over 2003.



Working with a set of depleting assets means we have to be smart with our capital spending as economic reserve growth is most important

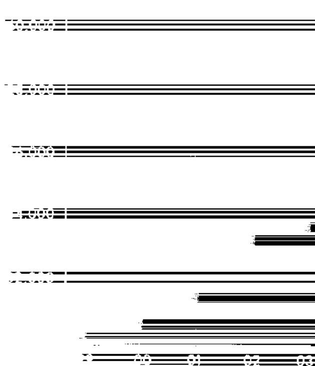


n our business. Technological ability combined with financial strength enables the Company to make timely decisions when responding to opportunities. These decisions are based on the prudent management of risk. We have a 2004 budget of $40 million to $45 million to drill 20 or more wells with a gross unrisked reserve potential of 219 Bcfe. In the petroleum industry where a company's asset base is depleted by its producing operations, an important benchmark is reserve growth. We have replaced on average more than 250% of our production at a cost of $1.93 per Mcfe since 1998, which is admirable for a Gulf of Mexico producer.



Capital Expenditures, $ 000s

While PetroQuest has undertaken ambitious Gulf of Mexico projects, we are evaluated against a strategic plan that balances geographical, geological and commodity diversity. Our prospect inventory is continuously upgraded and aligned to sustain a balance between low risk/moderate reward exploitation projects and high risk/higher reward exploration prospects. The primary objective of the lower risk projects is to grow production with moderate adds to reserves. The higher risk prospects give us exposure to larger reserve additions.



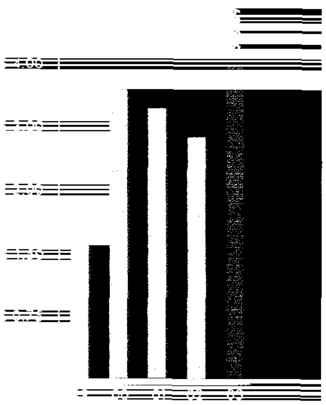
Gross Ultimate Recovery, MMcfe

Cumulative Extensions, Discoveries & Additions, MMcfe

Cumulative Production, MMcfe

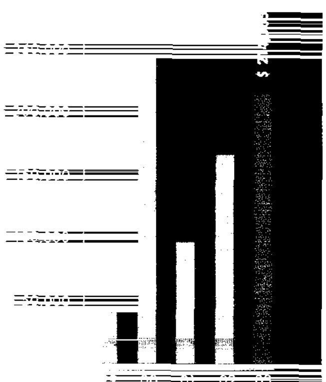
People, Motivation and Teamwork are the Formula for Success

Capital expenditures for 2003 were $53 million, including the acquisition of 29 Bcfe of proved reserves in East Texas for an attractive $0.79 per Mcfe. Over the course of the last six months of 2003, we placed six new wells on production. This activity pushed our 2003 exit rate to 32.7 MMcfe per day, or 23% higher than our full-year 2003 average daily rate of 26.5 MMcfe per day. We drilled an additional successful well which is expected to begin producing in the first quarter of 2004. For the



Gross Margin, $/Mcfe
Year Gross Margin ROI* 204%

Weighted average Gross Margin ROI = 5-year weighted average gross margin divided by a 5-year weighted average F&D, excluding revisions.



PV-10, Before Taxes, $ 000s
Year CAGR 49%

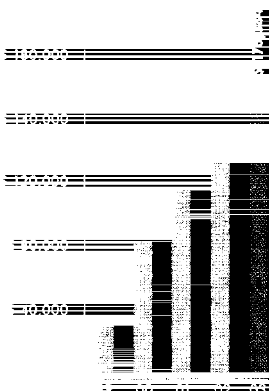
entire year, we drilled 10 wells of which eight were successful for an 80% success rate.

Like many oil and gas companies, PetroQuest values its business relationships and operating joint ventures. These are essential reasons for our growth and future expansion. As a prospect generator and operator, we can, to a degree, minimize the effects of competition and higher costs by controlling the timing of projects and investing prudently. We continue to operate the majority of our reserve base, quite an achievement for a company our size. We are able to attract partners for our prospects because we have experienced energy finders who are constantly generating and evaluating drilling prospects in our prolific focus area.

In last year's message, I outlined our growth strategies and how by adhering to our business model, we intended to put the company back on its growth track. Reserves at year-end 2003 are higher than the company record level posted in 2001; our 2004 plans forecast production and reserve increases. This 2004 plan provides the setting for renewed energy, novel approaches and fresh ideas, all of which will translate into new opportunities beyond the just-completed year. PetroQuest's primary objective continues to be the creation of long-term shareholder value by acquiring, exploring and developing high-quality oil and gas assets.

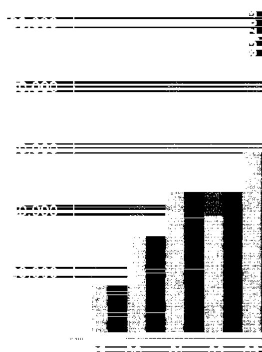
Defining Our Core Operations

PetroQuest has a diverse asset base comprised of high-quality, crude oil and natural gas reserves. These reserves generate the essential cash flow to support our operations and provide opportunities for exploration, exploitation and acquisitions. Our business success is rooted in our investing in high-quality projects that demonstrate excellent earnings potential. Our 2004 projects are expected to add to our daily production rate and year-end 2004 reserves. We continually add to our competitive edge through increasing our portfolio of quality opportunities. We re-allocate funds to develop other attractive oil and gas reserves as opportunities are uncovered. Such is the case with the East Texas property acquisition.



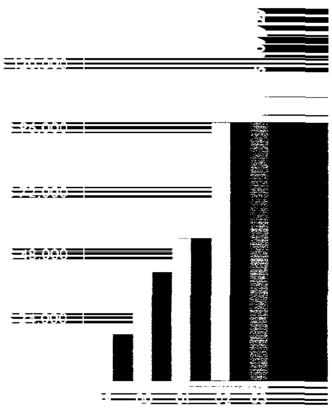
tal Assets, $ 000s
-Year CAGR 56%

PetroQuest acquired a 50% working interest in the Southeast Carthage Field in East Texas in late December in an all-debt transaction. Immediately accretive to net income and cash flow, this is a strategic addition of legacy assets with excellent potential for exploitation and development drilling. The property has 84 active wells developed on 320-acre spacing, with optional 80-acre spacing allowed. Daily production is 5.5 MMcfe, representing about 16% of our expected daily rate for the first quarter of 2004.



tal Proved Reserves, MMcfe
Oil
Gas

As a result of this transaction, PetroQuest's reserve base is more developed, 67% at December 31, 2003 versus 62% at December 31, 2002; balanced between onshore and offshore; and is longer lived with a reserve live index of 8.6 years at December 31, 2003, up from 5.2 years at December 31, 2002. These attributes increased our borrowing base, lowered our multi-year finding and development cost and should reduce our DD&A rate going forward.



Stockholders' Equity, $ 000s
Year CAGR 56%

Looking Ahead

Our fundamental goal is to continue creating value for investors by pursuing strategies that allow us to deliver a consistently strong performance. We made significant progress in 2003. We said production rates and reserve growth would return. Beginning with the third quarter, we realized increasing production rates. As of the date of this letter, we expect to produce more in 2004 than we produced in 2003. Reserves are higher at the end of 2003 than at the end of any of the previous five years. We plan for them to increase again in 2004. I said in my letter to you last year that we will gain much by keeping a clear mind, and by practicing patience and perseverance.

PetroQuest's vision of the future is clear. By fusing financial strength with prudent management of operational risk, we will continue to build a geologically diverse portfolio of assets leading to increased production and reserves. I am confident that in the coming years, substantial potential exists for increasing value to stockholders.

Best regards,

Charles T. Goodson

Charles T. Goodson
Chairman and Chief Executive Officer
March 1, 2004

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, 2003

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: 019020

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: None

Securities registered pursuant to Section 12 (g) of the Act:
Common Stock, Par Value $.001 Per Share
Preferred Stock Purchase Rights
(Title of Class)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

[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 an accelerated filer (as defined in Exchange Act Rule 12b-2).

[X] Yes [ ] No

The aggregate market value of the voting stock held by non-affiliates of the registrant was approximately $76,544,656 as of June 30, 2003 (based on the last reported sale price of such stock on The Nasdaq National Market System).

As of March 5, 2004, the registrant had outstanding 44,555,693 shares of Common Stock, par value $.001 per share.

Document incorporated by reference: Proxy Statement of PetroQuest Energy, Inc. relating to the Annual Meeting of Stockholders to be held on May 12, 2004, which is incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

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 include, without limitation, statements regarding our estimate of the sufficiency of our existing capital resources and our ability to raise additional capital to fund cash requirements for future operations, and regarding the uncertainties involved in estimating quantities of proved oil and natural gas reserves, in prospect development and property acquisitions and in projecting future rates of production, timing of development expenditures and drilling of wells 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" 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.

PART I

ITEM 1. BUSINESS

Overview

PetroQuest Energy, Inc. is incorporated in the State of Delaware and is an independent oil and gas company engaged in the generation, exploration, development, acquisition and operation of oil and gas properties onshore and offshore in the Gulf Coast Basin and East Texas area. Our business strategy is to increase production, cash flow and reserves through generation, exploration, development and acquisition of properties located in the Gulf Coast Region, as well as finding additional opportunities in areas with longer reserve lives.

On December 31, 2000, the Company underwent a corporate reorganization. The Company's subsidiary, PetroQuest Energy, Inc., a Louisiana corporation, was merged into PetroQuest Energy One, L.L.C., a Louisiana limited liability company. In addition, PetroQuest Energy One, L.L.C. changed its name to PetroQuest Energy, L.L.C., a single-member Louisiana limited liability company, and PetroQuest Energy, Inc., a Delaware corporation, continues to be its sole member.

Defined Terms

We have provided definitions for some of the oil and natural gas industry terms used in this Form 10-K in "Glossary of Oil and Natural Gas Terms" on page 37.

Our Strategy

Our business strategy is to build shareholder value by increasing per share reserves, production, cash flow and earnings at low finding and development costs through the exploration and development of properties located in the Gulf Coast Basin, either onshore or in shallow waters offshore, and the East Texas area. We plan to achieve this goal by continuing to:

- *Focus on the Gulf Coast Basin.* We have assembled a large acreage position and 3-D seismic database in the Gulf Coast Basin because we believe this area represents one of the most attractive exploration and development regions in North America. We also believe our management and technical team's expertise and experience developed over approximately the last 25 years will allow us to develop attractive reinvestment opportunities that will permit continuing growth.
- *Diversify our reserve base and technical expertise.* We have acquired a significant leasehold position in a producing portion of the

Southeast Carthage Field in the East Texas area. In addition, we have added appropriate personnel to our technical team to evaluate and exploit this area. The East Texas acquisition strengthens our asset base by adding reserves that have a longer life than our Gulf Coast reserves.

- *Target under-exploited fields that have low current production levels.* Using a rigorous prospect selection process that enables us to leverage our experience and knowledge of the Gulf Coast Basin, we target properties with an established production history and existing infrastructure. These fields have often produced from only shallower sands and contain multiple productive horizons that were not targeted during their initial phase of development. By targeting properties with limited current production, our acquisition costs are typically only a small portion of the total capital we will employ over the life of the project.
- *Emphasize and apply technical expertise.* By applying the latest 3-D and other geoscience technologies to under-exploited properties, we believe we can identify opportunities to significantly increase reserves and production from these properties.
- *Operate properties and balance risk.* By operating the majority of our properties, we can better control the timing and execution of our exploration and development plans. We also balance the risk and reward potential of our prospects by determining our desired working interest and selling the remainder to industry partners on terms where they often agree to pay a disproportionate share of drilling costs relative to their interests. Our management team has developed many successful relationships with major, integrated and large independent producers. We believe these relationships allow us to allocate our capital spending in a way that maximizes return while reducing the inherent risk of exploration activities.
- *Maintain our financial flexibility.* We seek to maintain unused borrowing capacity under our bank credit facility and sub-debt facility in order to take advantage of new opportunities. We also evaluate potential property acquisitions and dispositions, and routinely discuss those opportunities with third parties. While dispositions of producing properties reduce current revenues, sales of properties can provide additional capital for exploration and development of properties that are more important to our long-term growth.

Exploration and Development

We are engaged in the exploration, development, acquisition and operation of oil and gas properties onshore and offshore in the Gulf Coast Region, as well as the East Texas area. As of December 31, 2003, our estimated proved reserves totaled 4,245 MBbl of oil and 57,793 MMcf of natural gas, with 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 $214,365,000. Approximately 67% of our reserves are proved developed reserves. We operate 10 fields representing approximately 75% of the total discounted cash flow attributable to estimated proved reserves.

Significant Properties

Ship Shoal 72, Federal Outer Continental Shelf Waters. We retained a 100% working interest position in all wells drilled in this field prior to 2003. During 2003, we sold working interests in three wells to industry partners. During 2003, we drilled and completed three wells, and the field produced approximately 4.8 Bcfe net to us from twelve producing wells. Additional developmental opportunities and exploration potential in deeper horizons have been identified and are currently being evaluated for future drilling. Current plans call for one additional developmental well and one exploratory well to be drilled during 2004. We may continue to seek to obtain industry partners in the future development of this property. Reprocessed 3-D data is currently being reviewed for additional opportunities.

SE Carthage Field, Panola County, TX. During December 2003, we acquired a working interest in approximately 41,000 acres in this field, which had approximately 80 producing wells and produced approximately 5,500 Mcfe per day, net to us upon acquisition. Current plans call for seven developmental wells to be drilled during 2004.

Main Pass 74, Louisiana State Waters. We and our partners drilled a well on this property during the fourth quarter of 2003 and logged approximately 71 feet of net productive sands. The well began producing during 2003 at an initial gross rate of approximately 9,000 Mcfe per day. Current plans call for one additional developmental well to be drilled during the first quarter of 2004.

Turtle Bayou Field, Terrebonne Parish, LA. As of December 31, 2003, there are three producing wells in the field in which we hold a working interest. Collectively, the three producing wells averaged approximately 2,800 Mcf of natural gas and 90 barrels of oil per day, net to us, for the year ended December 31, 2003. Our working interest varies between 14% and 43% with a weighted average working interest of approximately 34%. As a result of reprocessing a 3-D regional seismic set shot in 1998, we have identified an additional prospect. Current plans call for us to drill an exploratory well during 2004.

Vermilion Block 376, Federal Outer Continental Shelf Waters ("Falcon Prospect"). We and our partners drilled a well on this property in the fourth quarter of 1999 and logged 285 feet of gross hydrocarbon column (136 feet net). An additional well was drilled in the second quarter of 2000 logging 112 feet of gross hydrocarbon pay (74 feet net). We are the operator of the project and own a 43% working interest. During 2000, an approximately 2,500 ton production platform was fabricated and placed in service. During 2003, the field produced at an average rate of approximately 420 Bbls per day of oil and 1,100 Mcf per day of natural gas, net to us.

Berry Lake Field, Iberville Parish, LA. We and our partners drilled a well on this property in the third quarter of 2002 and logged approximately 71 feet of net productive sands. During 2003, the well produced at an average rate of approximately 330 Bbls per day of oil and 500 Mcf per day of natural gas, net to us.

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 gas from our wells depends upon numerous factors beyond our control, including:

- the extent of domestic production and imports of oil and gas,
- the proximity of the gas production to gas pipelines,
- the availability of capacity in such pipelines,
- the demand for oil and 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 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 gas we produce or that favorable prices can be obtained for the oil and gas we produce.

In view of the many uncertainties affecting the supply and demand for oil, gas and refined petroleum products, we are unable to predict future oil and gas prices and demand or the overall effect such prices and demand will have on the Company. For the year ended December 31, 2003, we had five customers who accounted for 22%, 18%, 18%, 14% and 12% of total revenues, respectively. For the year ended December 31, 2002, we had three customers who accounted for 25%, 22% and 19% of total revenues, respectively. For the year ended December 31, 2001, we had four customers who accounted for 19%, 19%, 15% and 13% of total revenues, respectively. These percentages do not consider the effects of financial hedges. We do not believe that the loss of any of our oil or 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.

Beginning in April 1992, the FERC issued Order No. 636 and a series of related orders, which required interstate pipelines to provide open-access transportation on a not unduly discriminatory basis for all natural gas shippers. The FERC has stated that it intends for Order No. 636 and its future restructuring activities to foster increased competition within all phases of the natural gas industry. Although Order No. 636 does not directly regulate our production and marketing activities, it does affect how buyers and sellers gain access to the necessary transportation facilities and how we and our competitors sell natural gas in the marketplace.

The courts have largely affirmed the significant features of Order No. 636 and the numerous related orders pertaining to individual pipelines. However, some appeals remain pending and the FERC continues to review and modify its regulations regarding the transportation of natural gas. For example, the FERC issued Order No. 637 which;

- lifts the cost-based cap on pipeline transportation rates in the capacity release market until September 30, 2002, for short-term releases of pipeline capacity of less than one year;
- permits pipelines to file for authority to charge different maximum cost-based rates for peak and off-peak periods;
- encourages, but does not mandate, auctions for pipeline capacity;
- requires pipelines to implement imbalance management services;
- restricts the ability of pipelines to impose penalties for imbalances, overruns and non-compliance with operational flow orders; and
- implements a number of new pipeline reporting requirements.

Order No. 637 also requires the FERC staff to analyze whether the FERC should implement additional fundamental policy changes. These include whether to pursue performance-based or other non-cost based ratemaking techniques and whether the FERC should mandate greater standardization in terms and conditions of service across the interstate pipeline grid.

In April 1999 the FERC issued Order No. 603, which implemented new regulations governing the procedure for obtaining authorization to construct new pipeline facilities. In September 1999, the FERC issued a related policy statement establishing a presumption in favor of requiring owners of new pipeline facilities to charge rates for service on new pipeline facilities based solely on the costs associated with such new pipeline facilities. There have been recent instances when FERC and the courts have disagreed as to the proper tests to apply in determining whether certain natural gas gathering systems in the shallow waters of the OCS are subject to transportation lines subject to FERC jurisdiction or exempt as gathering lines. In response to sometimes confusing and conflicting decisions, FERC convened a public conference on September 23, 2003 to explore whether it should reformulate its tests for defining non jurisdictional gathering in the shallow waters of the OCS. Costs to transport gas from offshore leases to market is subject to FERC rules and tariffs while non jurisdictional gathering lines may charge market rates.

We cannot predict what further action the FERC will take on these matters, nor can we accurately predict whether the FERC's actions will achieve the goal of increasing competition in markets in which our natural gas is sold. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers.

The Outer Continental Shelf Lands Act, which the FERC implements as to transportation and pipeline issues, requires that all pipelines operating on or across the Outer Continental Shelf provide open-access, non-discriminatory service. Historically, the FERC has opted not to impose regulatory requirements under its Outer Continental Shelf Lands Act authority on gatherers and other entities outside the reach of its NGA jurisdiction. However, the FERC in 2000 issued Order No. 639 and 639-A, requiring that virtually all non-proprietary pipeline transporters of natural gas on the Outer Continental Shelf report information on their affiliations, rates and conditions of service. The reporting requirements established by the FERC in Order No. 639 and 639-A may apply, in certain circumstances, to operators of production platforms and other facilities on the Outer Continental Shelf, with respect to gas movements across such facilities.

The FERC retains authority under the Outer Continental Shelf Lands Act to exercise jurisdiction over gatherers and other entities outside the reach of its NGA jurisdiction if necessary to ensure non-discriminatory access to service on the Outer Continental Shelf. We do not believe that any FERC action taken under its Outer Continental Shelf Lands Act jurisdiction will affect us in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue.

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. The FERC indicated in Order No. 561 that it will assess in 2000 how the rate-indexing method is operating. The FERC issued a Notice of Inquiry on July 27, 2000 seeking comment on whether to retain or to change the existing index. After consideration of all the initial and reply comments, the FERC concluded on December 14, 2000 that the PPI-1 index has reasonably approximated the actual cost changes in the oil pipeline industry during the preceding five year period, and that it should be continued for the subsequent five year period.

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

For offshore operations, lessees must obtain Minerals Management Service 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 Environmental Protection Agency, lessees must obtain a permit from the Minerals Management Service prior to the commencement of drilling. The Minerals Management Service has promulgated regulations requiring offshore production facilities located on the Outer Continental Shelf to meet stringent engineering and construction specifications. The Minerals Management Service 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 Minerals Management Service 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 Minerals Management Service 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. Under some circumstances, the Minerals Management Service may require operations on federal leases to be suspended or terminated.

The Minerals Management Service also administers the collection of royalties under the terms of the Outer Continental Shelf Lands Act 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 Minerals Management Service. 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 Minerals Management Service. 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, gathers 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 Minerals Management Service 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 natural gas facilities, including the operation and construction of pipelines, plants and other facilities for transporting, processing, treating or storing natural gas and other products, are subject to stringent environmental regulation by state and federal authorities including the United States Environmental Protection Agency ("EPA"). 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 EPA has limited the disposal options for certain hazardous wastes. Furthermore, it is possible that certain wastes currently exempt from regulation as "hazardous wastes" generated by our oil and gas operations 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 the hazardous substances found at a site. CERCLA also authorizes the EPA 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. Neither we nor our predecessors have been designated as a potentially responsible party by the EPA under CERCLA 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 40,000 square feet of leased space, with an exploration office in Houston, Texas, in approximately 5,500 square feet of leased space. We also maintain owned or leased field offices in the area 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 44 employees as of December 31, 2003. 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

PetroQuest's Internet website can be found at www.petroquest.com. We make available free of charge, or through the "Financials" section of our Internet 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.

Risk Factors

Risks Related to Our Business, Industry and Strategy

Our future success depends upon our ability to find, develop 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. As a result, we must 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.

We may not be able to maintain our historical rates of growth.

We may not be able to maintain the rate of growth in our reserves, production and financial results that we have achieved since our management team acquired its equity interest in PetroQuest. Our growth rates have to a certain extent been unusually high because PetroQuest was a very small company, with total reserves of approximately 14 Bcfe as of December 31, 1998. As a result, if we continue to grow, our growth rates may be lower than those achieved in our recent history.

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 us.

Our revenues, 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 depend 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 and the demand for oil and natural gas;
- market uncertainty;
- the level of consumer product demand;
- weather conditions in the United States;
- the condition of the United States economy;
- the action 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 foreign supply of oil and natural gas;
- the price of foreign imports; and
- the 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 prices may decline. Declines in oil and natural gas prices may adversely affect our financial condition, liquidity 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.

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

This document contains estimates of oil and natural gas reserves, and the future net cash flows attributable to those reserves, prepared by Ryder Scott Company, L.P., our independent petroleum and geological engineers. There are 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 addition, reserve engineers may make different estimates of reserves and cash flows based on the same available data. In calculating reserves on a 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. While this ratio approximates the energy equivalency of natural gas to oil or natural gas liquid on a Btu basis, it may not represent the relative prices received by us from the sale of our oil or natural gas liquid and natural gas production.

Approximately 33% of our estimated proved reserves are undeveloped. Estimates of undeveloped 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 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.

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 Securities and Exchange Commission requirements, the estimated discounted future net cash flows from proved reserves are generally 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 Securities and Exchange Commission to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate 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.

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 "ceiling limit" 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 net capitalized costs of oil and natural gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. 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.

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;
- 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 intermediate 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.

Risks Relating to Financing Our Business

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

We have historically addressed our long-term liquidity needs through the use of credit facilities, sub-debt facilities, the issuance of equity securities and the use of cash provided by operating activities. We 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 and our market value and operating performance. We may be unable to execute our operating strategy if we cannot obtain capital from these sources.

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 complete 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.

Leverage may materially affect our operations.

We presently have and may incur from time to time debt under our bank credit facility and sub-debt facility. The borrowing base limitation on 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 level of debt affects our operations in several important ways, including the following:

- a portion of our cash flow from operations is used to pay interest on borrowings;
- the covenants contained in the agreements governing our debt limit our ability to borrow additional funds or to dispose of assets;
- the covenants contained in the agreements governing our debt may affect our flexibility in planning for, and reacting to, changes in business conditions;
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes;
- our leveraged financial position may make us more vulnerable to economic downturns and may limit our ability to withstand competitive pressures;
- any debt that we incur under our credit facilities will be at variable rates, which could make us vulnerable to increases in interest rates; and
- a high level of debt will affect our flexibility in planning for or reacting to changes in market conditions.

In addition, we may significantly alter our capitalization in order to make future acquisitions or develop our properties. These changes in capitalization may significantly increase our level of debt. A higher level of debt increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of debt depends on our future performance. General economic conditions and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control.

If we are unable to repay our debt at maturity out of cash on hand, we could attempt to refinance such debt, or repay such debt with the proceeds of an equity offering. We cannot assure you that we will be able to generate sufficient cash flow to pay the interest on our debt or that future borrowings or equity financing will be available to pay or refinance such debt. The terms of our bank credit facility and sub-debt facility may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions and our market value and operating performance at the time of such offering or other financing. We cannot assure you that any such offering or refinancing can be successfully completed.

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 cashless collars or swap contracts and are placed with major trading counter parties we believe represent minimum credit risks. We cannot assure you that these trading counter parties will not become credit risks in the future. Hedging arrangements expose us to risks in some circumstances, including situations when the other party to the hedging contract defaults on its 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 prices for natural gas and oil. 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.

Risks Relating to Our Ongoing Operations

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

Our operations are dependent upon a relatively small group of key management and technical personnel. 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 these individuals could have a detrimental 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.

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 maritime employer's liability and comprehensive general liability. Amounts over base coverages are provided by primary and excess umbrella liability policies with maximum limits of $50 million. We also maintain operator's extra expense coverage, which covers the control of drilled or producing wells as well as redrilling expenses and pollution coverage for wells out of control.

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

Compliance with environmental and other government regulations is costly and could negatively impact production.

Our operations are subject to numerous 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 recent 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 particular 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 Common Stock Outstanding

Our management controls a significant percentage of our outstanding common stock and their interests may conflict with those of our stockholders.

Our directors and executive officers and their affiliates beneficially own about 20.3% of our outstanding common stock at March 1, 2004. If these persons were to act in concert, they would, as a practical matter, be able to effectively control our affairs. This concentration of ownership could also have the effect of delaying or preventing a change in control of or otherwise discouraging a potential acquirer from attempting to obtain control of us. This could have a material adverse effect on the market price of our common stock or prevent our stockholders from realizing a premium over the then prevailing market prices for their shares of our 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 exploration and development drilling program, 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.

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 exercise of any outstanding stock awards. 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.

We have reserved approximately 4.3 million shares of common stock for issuance under outstanding options. These shares of common stock are registered for resale on currently effective registration statements. In addition, we have registered the resale of approximately 13.1 million shares of common stock that were issued in private placements to accredited investors in 1999 and 2000, and have granted piggy-back registration rights with respect to 2.25 million shares of common stock underlying a warrant. 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, 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, shareholder rights plan and Delaware law 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 and the provisions of Delaware General Corporation Law 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; and
- a restriction on the ability of stockholders to take actions by written consent.

We are also subject to Section 203 of the Delaware General Corporation Law, which generally prohibits a Delaware corporation from engaging in any of a broad range of business combinations with an interested stockholder for a period of three years following the date on which the stockholder became an interested stockholder.

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.

Notice Regarding Consent Of Arthur Andersen LLP

On June 15, 2002, Arthur Andersen LLP, our former independent auditors, was convicted of federal obstruction of justice. On June 28, 2002, our Board of Directors, upon the approval of its Audit Committee, engaged Ernst & Young, LLP as independent auditors and dismissed Arthur Andersen LLP. After reasonable efforts, we have not been able to obtain the consent of Arthur Andersen LLP to the incorporation by reference of its audit report dated March 7, 2002 into our registration statements on Form S-3 and Form S-8. As permitted under Rule 437a promulgated under the Securities Act of 1933, we have not filed the written consent of Arthur Andersen LLP that would otherwise be required by the Securities Act. Because Arthur Andersen LLP has not consented to the incorporation of reference of their report in these registration statements, you may not be able to recover amounts from Arthur Andersen LLP under Section 11(a) of the Securities Act for any untrue statement of a material fact or any omission to state a material fact, if any, contained in or omitted from our financial statements included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2001, which are incorporated by reference in these registration statements.

ITEM 2. PROPERTIES

For a description of the Company's exploration and development activities and its significant properties, see Item 1. Business - Exploration and Development and - Significant Properties.

Oil and Gas Reserves

The following table sets forth certain information about the estimated proved reserves of the Company as of December 31, 2003.

		Oil MBbls	Gas and NGL MMcfe
Proved developed:		3,446	34,655
Proved undeveloped:		799	23,138
Total proved:		4,245	57,793
Estimated pre-tax future net cash flows	$	293,348,933	
Discounted pre-tax future net cash flows	$	214,364,855	
Standardized measure of discounted future net cash flows	$	175,225,692	

Ryder Scott Company, L.P. prepared the estimates of proved reserves and future net cash flows (and present value thereof) attributable to such proved reserves at December 31, 2003. Reserves were estimated using oil and gas prices and production and development costs in effect at December 31, 2003 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 $32.24 per Bbl of oil and $5.58 per MMBtu of gas. Because of the high Btu content of our Gulf Coast gas, this equates to an average price realized of approximately $6.02 per Mcf. The above cash flow amounts include a reduction for estimated plugging and abandonment costs that will also be reflected as a liability on our balance sheet at December 31, 2003, in accordance with Statement of Financial Standards No. 143.

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

Oil and Gas Drilling Activity

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

	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Exploration:						
Productive	4	1.55	2	1.72	1	0.41
Non-productive	2	1.20	1	0.50	2	0.68
Total	6	2.75	3	2.22	3	1.09
Development:						
Productive	4	1.96	5	4.02	9	5.78
Non-productive	-	-	2	0.77	1	0.54
Total	4	1.96	7	4.79	10	6.32

We owned working interests in 113 gross (88.4 net) producing oil and gas wells at December 31, 2003. At December 31, 2003, we had no wells in progress.

Leasehold Acreage

The following table shows our approximate developed and undeveloped (gross and net) leasehold acreage as of December 31, 2003:

	Leasehold Acreage			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Mississippi (onshore)	721	458	1,438	913
Louisiana (onshore)	3,025	701	4,415	1,638
Louisiana (offshore)	674	454	-	-
Oklahoma (onshore)	627	627	2,791	2,442
Texas (onshore)	16,446	8,180	25,044	12,949
Federal Waters	39,103	16,525	55,398	35,481
Total	60,596	26,945	89,086	53,423

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

There are no legal proceedings to which PetroQuest or its subsidiaries is a party or by which any of its property is subject, other than ordinary and routine litigation due to the business of producing and exploring for oil and natural gas.

On December 10, 2003, our wholly owned subsidiary, PetroQuest Energy, L.L.C. ("PetroQuest Energy") entered into a settlement agreement with The Meridian Resource & Exploration LLC relating to the litigation "*PetroQuest Energy, Inc. f/k/a Optima Energy (U.S.) Corp. v. The Meridian Resource & Exploration Company f/k/a Texas Meridian Resources Exploration, Inc.,* bearing Civil Action No. 99-2394 of the United States District Court for the Western District of Louisiana" and "*The Meridian Resource & Exploration Company v. PetroQuest Energy, Inc.,* bearing Docket No. 996192A of the 15th Judicial District Court in and for Lafayette Parish, Louisiana" which related to our Southwest Holmwood property in Calcasieu Parish, Louisiana.

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 2003.

PART II

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

Market Price of and Dividends on Common Stock

Our common stock trades on The Nasdaq Stock Market under the symbol "PQUE." The following table lists high and low sales prices per share for the periods indicated:

	NASDAQ Stock Market	
Quarter Ended	High	Low
	(U.S.$)	(U.S.$)
2002		
1st Quarter	6.49	4.20
2nd Quarter	6.85	5.20
3rd Quarter	5.75	3.65
4th Quarter	5.05	3.61
2003		
1st Quarter	4.37	1.48
2nd Quarter	2.79	1.20
3rd Quarter	2.48	1.85
4th Quarter	3.34	2.00

As of March 5, 2004, there were approximately 529 common stockholders of record.

We have not paid dividends on the common stock and intend to retain our cash flow from operations for the future operation and development of its business. In addition, the bank credit facility and sub-debt facility restrict the declaration or payment of any dividends or distributions.

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, 2003 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.

	Years Ended December 31,				
	2003	2002	2001 (a)	2000 (a)	1999 (a)
	(in thousands except share data)				
Revenues	$ 48,688	$ 48,238	$ 55,342	$ 22,561	$ 8,607
Net Income (Loss)	3,640	2,307	11,645	9,924	(310)
Net Income (Loss) per share:					
Basic	0.08	0.06	0.37	0.37	(0.01)
Diluted	0.08	0.06	0.34	0.35	(0.01)
Oil and Gas Properties, net	160,229	120,746	101,029	56,344	21,490
Total Assets	176,384	132,063	114,639	83,072	29,901
Long-term Debt	22,200	2,400	33,000	6,804	2,927
Stockholders' Equity	107,727	97,770	54,215	41,456	18,105

(a) The Company's financial statements for 1999-2001 were audited by Arthur Andersen LLP, which has ceased operations.

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

General

PetroQuest is an independent oil and gas company engaged in the exploration, development, acquisition and operation of oil and gas properties onshore and offshore in the Gulf Coast Region and the East Texas area. We have been active in the Gulf Coast area since 1986, which gives us extensive geophysical, technical and operational expertise in this area. Our business strategy is to increase production, cash flow and reserves through exploration, development and acquisition of properties located in the Gulf Coast Region, as well as finding additional opportunities in areas with longer reserve lives.

During 2003, the Company completed a $20 million subordinated term credit facility with Macquarie Americas Corp. ("Macquarie"). The sub-debt facility is available for advances at any time until December 31, 2004 subject to restrictive covenants. Macquarie received warrants to purchase 2,250,000 of our common stock at an exercise price of $2.30 per share. We also completed an acquisition in the Southeast Carthage Field in East Texas during 2003. This property increased our proved reserves by approximately 29 Bcfe and was funded primarily through our credit facilities. As a result of this acquisition, we expect an increase in our 2004 production rate and revenues, as well as an increase in operating expenses and interest expense.

New Accounting Standards

In June 2001, the Financial Accounting Standards Board issued SFAS 143, "Accounting for Asset Retirement Obligations," which requires recording the fair value of an asset retirement obligation associated with tangible long-lived assets in the period incurred. 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.

We adopted SFAS 143 effective January 1, 2003. The net difference between our previously recorded abandonment liability and the amounts estimated under SFAS 143, after taxes, totaled a gain of $849,000, which has been recognized as a cumulative effect of a change in accounting principle. The gain is due to the effect on the historical depletion as a result of the retirement obligation being recorded at fair value. On a pro forma basis, the impact for the year ended December 31, 2002 would have increased net income by approximately $360,000.

We have legal obligations to plug, abandon and dismantle existing wells and facilities that we have acquired and constructed during our existence. As of January 1, 2003, we recognized a $9,467,000 liability for our asset retirement obligations and recorded the related additional assets that will be depreciated using the unit-of-production method.

In January 2003, the Financial Accounting Standards Board issued Interpretation No. 46, Consolidation of Variable Interest Entities (FIN 46), which requires companies to evaluate variable interest entities to determine whether to apply the consolidation provisions of FIN 46 to those entities. The consolidation provisions of FIN 46, if applicable, would apply to variable interest entities created after January 31, 2003 immediately, and to variable interest entities created before February 1, 2003 in our interim period beginning October 1, 2003. We believe that we have no interests in these types of entities.

Critical Accounting Policies

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 and 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 related to 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 and dismantlement, restoration and abandonment costs, net of estimated salvage values. 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 the 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. For purposes of calculating the full cost ceiling test, the liability recognized under SFAS 143 is netted against property cost and the future abandonment obligations are included in estimated future net cash flows.

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.

In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 141, "Business Combinations," which requires the use of the purchase method of accounting for business combinations initiated after June 30, 2001 and eliminates the pooling-of-interests method. In July 2001, the FASB also issued SFAS No. 142, "Goodwill and Other Intangible Assets," which discontinues the practice of amortizing goodwill and indefinite lived intangible assets and initiates an annual review of impairment. The new standard also requires that, at a minimum, all intangible assets be aggregated and presented as a separate line item in the balance sheet. The adoption of SFAS No. 141 and 142 had no impact on our financial position or results of operations. A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141 and 142 to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires registrants to classify the costs of mineral rights associated with extracting oil and gas as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, we have included the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties. These costs include those to acquire contract based drilling and mineral use rights such as delay rentals, lease bonuses, commissions and brokerage fees, and other leasehold costs. If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify these costs as a separate item on the balance sheet, we would be required to reclassify approximately $27.5-$28.5 million at December 31, 2003 and approximately $5-$6 million at December 31, 2002. Our cash flows and results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with full cost accounting rules, as allowed by SFAS No. 142. Further, we believe the classification of the costs of mineral rights associated with extracting oil and gas as intangible assets would have an impact on our compliance with the minimum tangible net worth covenant under our bank credit facility.

PetroQuest will continue to classify its oil and gas leasehold costs as tangible oil and gas properties until further guidance is provided. We anticipate there will be no effect on our results of operations or cash flows.

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 and the political and regulatory environment. The accounting for future abandonment costs changed on January 1, 2003, with the adoption of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations." See New Accounting Standards in the Notes to Consolidated Financial Statements for a further discussion of this accounting standard.

Reserve Estimates

Our estimates of oil and gas reserves are, by necessity, 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 treatment due to being highly effective are recorded to Other Comprehensive Income until the hedged oil or natural gas quantities are produced. If a hedge becomes ineffective because the expected event does not occur, the fair value of the derivative is recorded on the income statement. One of our derivatives was deemed ineffective during 2003 because of a decline in production in the specific field to which the derivative was designated.

Estimating the fair values of hedging derivatives requires complex calculations incorporating estimates of future prices, discount rates and price movements. Instead, we choose to obtain the fair value of our commodity derivatives from the counter parties to those contracts. Since the counter parties are market makers, they are able to provide us with a literal market value, or what they would be willing to settle such contracts for as of the given date.

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, 2003, 2002 and 2001:

	Year Ended December 31,		
	2003	2002	2001
Production:			
Oil (Bbls)	744,575	929,181	791,405
Gas (Mcf)	5,192,760	7,765,142	9,025,240
Total Production (Mcfe)	9,660,210	13,340,228	13,773,670
Sales:			
Total oil sales	$ 21,196,246	$ 23,294,514	$ 20,171,659
Total gas sales	26,713,611	24,846,723	34,794,876
Average sales prices:			
Oil (per Bbl)	$ 28.47	$ 25.07	$ 25.49
Gas (per Mcf)	5.14	3.20	3.86
Per Mcfe	4.96	3.61	3.99

The above sales include income (loss) related to gas hedges of ($2,540,000), ($733,000) and $1,247,000 and oil hedges of ($1,923,000), ($128,000) and $384,000 for the years ended December 31, 2003, 2002 and 2001, respectively.

Comparison of Results of Operations for the Years Ended December 31, 2003 and 2002

Net income totaled $3,640,000 and $2,307,000 for the years ended December 31, 2003 and 2002, respectively. The results are attributable to the following components:

Production

Oil production in 2003 decreased 20% from the year ended December 31, 2002. Natural gas production in 2003 decreased 33% from the year ended December 31, 2002. On a Mcfe basis, total production for the year ended December 31, 2003 decreased 28% over the same period in 2002. The decrease in 2003 total production volumes, as compared to 2002, was due to the consistent decline of our Gulf Coast production and well performance at our Bordeaux and Berry Lake wells, partially offset by the drilling success during the second half of 2003.

Prices

Average oil prices per Bbl during 2003 were $28.47 as compared to $25.07 for the same period in 2002. Average gas prices per Mcf were $5.14 during 2003 as compared to $3.20 for the same period in 2002. Stated on a Mcfe basis, unit prices received during 2003 were 37% higher than the prices received during 2002.

Revenue

Oil and gas sales during 2003 decreased to $47,910,000 as compared to 2002 revenues of $48,141,000. The decrease in production volumes partially offset by the significant increase in realized commodity prices resulted in the decrease in revenue.

Interest and other income during 2003 increased to $778,000 as compared to $97,000 during 2002. The increase is primarily the result of the settlement of a lawsuit during 2003 and the related accounting entries as a result of the settlement.

Expenses

Lease operating expenses for 2003 decreased to $9,449,000 from $9,988,000 during 2002. On a Mcfe basis, lease operating expenses increased from $0.75 per Mcfe in 2002 to $0.98 in 2003. The increase during 2003 on a Mcfe basis is primarily due to an overall decline in production rates and the repairs and maintenance costs at the Ship Shoal 72 Field, which did not increase production rates.

General and administrative expenses during 2003 totaled $4,444,000 as compared to expenses of $5,009,000 during 2002, net of amounts capitalized of $3,611,000 and $3,664,000, respectively. The decreases in general and administrative expenses are primarily due to a decrease in staffing levels during the current year. We recognized $381,000 and $345,000 of non-cash compensation expense during 2003 and 2002, respectively.

Depreciation, depletion and amortization ("DD&A") expense for 2003 decreased 4% to $27,098,000 as compared to $28,196,000 in 2002. On a Mcfe basis, which reflects the changes in production, the DD&A rate for 2003 was $2.81 per Mcfe as compared to $2.11 per Mcfe for 2002. The increase in 2003 as compared to 2002 is due primarily to costs in excess of previous estimates during the previous twelve months and unsuccessful exploration drilling results during 2002 and 2003.

Interest expense, net of amounts capitalized on unevaluated prospects, increased $301,000 during 2003 as compared to 2002. The increase is the result of an increase in the average debt levels during 2003, the higher interest rates on the new subordinated term credit facility and the previously capitalized costs that were expensed on our prior credit facility. We capitalized $451,000 and $619,000 of interest during 2003 and 2002, respectively.

Derivative expense increased $513,000 during 2003 as compared to 2002. This increase is primarily the result of one of our gas derivatives being recorded on the income statement because of a decline in production in the specific field to which the derivative was designated. The monthly settlements related to this derivative have been recorded to derivative expense effective during June 2003.

Income tax expense of $1,690,000 was recognized during 2003 as compared to $1,288,000 being recorded during 2002. The increase is due to an increase in operating profit during the current year. We provide for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, primarily statutory depletion.

Comparison of Results of Operations for the Years Ended December 31, 2002 and 2001

Net income totaled $2,307,000 and $11,645,000 for the years ended December 31, 2002 and 2001, respectively. The results are attributable to the following components:

Production

Oil production in 2002 increased 17% over the year ended December 31, 2001. Natural gas production in 2002 decreased 14% over the year ended December 31, 2001. On a Mcfe basis, total production for the year ended December 31, 2002 decreased 3% over the same period in 2001. The decrease in 2002 total production volumes, as compared to 2001, was due to the consistent decline of our Gulf Coast production partially offset by the drilling success during 2002.

Prices

Average oil prices per Bbl during 2002 were $25.07 as compared to $25.49 for the same period in 2001. Average gas prices per Mcf were $3.20 during 2002 as compared to $3.86 for the same period in 2001. Stated on a Mcfe basis, unit prices received during 2002 were 10% lower than the prices received during 2001.

Revenue

Oil and gas sales during 2002 decreased 12% to $48,141,000 as compared to 2001 revenues of $54,967,000. The slight decrease in production volumes and reduced commodity prices resulted in the decrease in revenue.

Expenses

Lease operating expenses for 2002 increased to $9,988,000 from $7,172,000 during 2001. On a Mcfe basis, lease operating expenses increased from $0.52 per Mcfe in 2001 to $0.75 in 2002. The increase during 2002 is primarily due to increased insurance costs and an increase in the repairs and maintenance at the Ship Shoal 72 Field.

General and administrative expenses during 2002 totaled $5,009,000 as compared to expenses of $4,752,000 during 2001, net of amounts capitalized of $3,664,000 and $2,651,000, respectively. The increases in general and administrative expenses are primarily due to an increase in staffing levels and rent expense related to the generation of prospects, exploration for oil and gas reserves and operation of properties. We recognized $345,000 and $765,000 of non-cash compensation expense during 2002 and 2001, respectively.

DD&A expense for 2002 increased 22% to $28,196,000 as compared to $23,094,000 in 2001. On a Mcfe basis, which reflects the changes in production, the DD&A rate for 2002 was $2.11 per Mcfe as compared to $1.68 per Mcfe for 2001. The increase in 2002 as compared to 2001 is due primarily to costs in excess of previous estimates during the previous twelve months and unsuccessful exploration drilling results during 2002.

Interest expense, net of amounts capitalized on unevaluated prospects, decreased $1,833,000 during 2002 as compared to 2001. The decrease is the result of an decrease in the average debt levels and interest rates during 2002. We capitalized $619,000 and $1,001,000 of interest during 2002 and 2001, respectively.

Income tax expense of $1,288,000 was recognized during 2002 as compared to $5,411,000 being recorded during 2001. The decrease is due to a decrease in operating profit during the current year. We provide for income taxes at a statutory rate of 37% adjusted for permanent differences expected to be realized, primarily statutory depletion.

Liquidity and Capital Resources

We have financed our exploration and development activities to date principally through cash flow from operations, bank borrowings, private and public offerings of common stock and sales of properties.

Source of Capital: Operations

Net cash flow from operations during the year increased from $29,178,000 in 2002 to $33,163,000 in 2003. The change resulted primarily from changes in the working capital accounts during the current year as compared to 2002. The working capital deficit decreased from $(15.8) million at December 31, 2002 to $(15.3) million at December 31, 2003. This decrease was caused primarily by our effort to utilize cash flow to first reduce our working capital deficit and second to drill prospects.

Source of Capital: Debt

We entered into a new bank credit facility on May 14, 2003. Pursuant to the new credit facility agreement, PetroQuest and our subsidiary PetroQuest Energy, L.L.C. (the "Borrower") have a $75 million revolving credit facility which permits us to borrow amounts from time to time based on our available borrowing base as determined in the bank credit facility. The bank credit facility is secured by a mortgage on substantially all of the Borrower's oil and gas properties, a pledge of the membership interest of the Borrower and PetroQuest's corporate guarantee of the indebtedness of the Borrower. The borrowing base under the bank credit facility is based upon the valuation as of April 1 and October 1 of each year of the Borrower's mortgaged properties, projected oil and gas prices, and any other factors deemed relevant by the lenders. We or the lenders may also request additional borrowing base redeterminations. As of December 31, 2003, the borrowing base under the bank credit facility was $20.2 million and is subject to monthly reductions of $1 million commencing March 1, 2004. We have recently completed a borrowing base redetermination as of March 1, 2004, and the borrowing base is $21.2 million and subject to monthly reductions of $1.25 million commencing on July 1, 2004. The bank will determine future monthly reductions in connection with each borrowing base redetermination.

Outstanding balances on the revolving credit facility bear interest at either the bank's prime rate plus a margin (based on a sliding scale of 0.75% to 1.25% based on borrowing base usage but never less than the Federal Funds Effective Rate plus 0.5%) or the Eurodollar rate plus a margin (based on a sliding scale of 2.0% to 2.5% depending on borrowing base usage). The bank credit facility also allows us to use up to $5 million of the borrowing base for letters of credit for fees equal to the applicable margin rate for Eurodollar advances. At March 5, 2004, we had $15.5 million of borrowings and no letters of credit issued pursuant to the bank credit facility.

We are subject to certain restrictive financial and non-financial covenants under the bank credit facility, including a minimum current ratio of 1.0 to 1.0, all as defined in the credit facility agreement. The bank credit facility also requires the Borrower to establish and maintain commodity hedges covering at least 50% of its proved developed producing reserves on a rolling twelve month basis. As of December 31, 2003, we were in compliance with all of the covenants in the bank credit facility. The bank credit facility matures on May 14, 2006.

On November 6, 2003, we obtained a $20 million subordinated term credit facility from Macquarie. The sub-debt facility carries an interest rate of prime plus 5.5%, is secured by a second mortgage on substantially all of our oil and gas properties and matures November 30, 2006. The sub-debt facility is available for advances at any time until December 31, 2004 subject to the restrictive covenants of the sub-debt facility and Macquarie approval. At closing, Macquarie received warrants to purchase 1,250,000 shares of our common stock at an exercise price of $2.30 per share. When cumulative advances under the sub-debt facility exceeded $5 million, $10 million and $15 million, Macquarie was to receive warrants to purchase an additional 250,000 shares, 500,000 shares and 250,000 shares of our common stock, respectively, at the same exercise price per share. In conjunction with the December 23, 2003 property acquisition, the sub-debt facility was amended and the original warrant was cancelled and reissued at which time all 2,250,000 warrants were issued to Macquarie. The warrants are exercisable at any time through the earlier of 36 months following the repayment in full of the sub-debt facility or 30 days after daily volume weighted average price of our common stock as published by Nasdaq is equal to or greater than, for a period of 30 days, the exercise price multiplied by three. In addition, we granted Macquarie piggy-back registration rights with respect to the shares of common stock issuable upon exercise of the warrants.

As of December 31, 2003, we had $12 million borrowed under the sub-debt facility which was primarily used to fund our acquisition of properties in the Southeast Carthage Field. The sub-debt facility, as amended, contains certain restrictive financial and non-financial covenants, including a minimum current ratio of 1.0 to 1.0, a total debt threshold of $45 million and a cumulative minimum production and net operating cash flow threshold, all as defined in the sub-debt facility. The sub-debt facility also requires us to establish and maintain commodity hedges covering at least 65% of its proved developed producing reserves through November 2006. As of December 31, 2003, we were in compliance with all of the covenants in the sub-debt facility.

During January 2004, the sub-debt facility, including the note, liens, warrants and all other rights of Macquarie thereunder, was assigned to Macquarie Bank Limited, an affiliate of Macquarie Americas Corp.

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. Additionally, the production declines of certain producing wells resulted in lower production during the year ended December 31, 2003. 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. Although we do not anticipate debt covenant violations, our ability to comply with 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 Equity Securities

We have an effective universal shelf registration statement relating to the potential public offer and sale by PetroQuest of any combination of debt securities, common stock, preferred stock, depositary shares, and warrants from time to time or when financing needs arise. The registration statement does not provide assurance that we will or could sell any such securities.

During October and November 2002, we completed the offering of 5,000,000 shares of our common stock. The shares were sold to the public for $4.25 per share. After underwriting discounts, we realized proceeds of approximately $20.4 million.

During February and March 2002, we completed the offering of 5,193,600 shares of our common stock. The shares were sold to the public for $4.40 per share. After underwriting discounts, we realized proceeds of approximately $21.9 million.

Source of Capital: Sales of Properties

On March 1, 2002, we closed the sale of our interest in Valentine Field for $18.6 million. The transaction had an effective date of January 1, 2002. At December 31, 2001, our independent reservoir engineering firm attributed 7.3 Bcfe of proved reserves net to our interest in this field. Consistent with the full cost method of accounting, we did not recognize any gain or loss as a result of this sale. The proceeds were treated as a reduction of the full cost pool.

Use of Capital: Exploration and Development

We have an exploration and development program budget for the year 2004 which will require significant capital. Our capital budget for new projects in 2004 is approximately $45-50 million of which approximately 80% will be incurred in the Gulf Coast region and the remaining 20% in other areas. Our management believes the cash flows from operations and available borrowing capacity under our credit facilities, will be sufficient to fund planned 2004 exploration and development activities. In the future, our exploration and development activities could require additional financings, which may include sales of additional equity or debt securities, additional borrowings from banks or other lenders, 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 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, 2003:

	2004	2005	2006	2007	2008	After 2008
Bank debt	5,300	12,200	-	-	-	-
Subordinated debt	-	-	12,000	-	-	-
Operating leases (1)	741	806	744	703	699	1,363
Capital projects (2)	1,054	1,694	314	124	306	8,985

(1) Consists primarily of leases for office space and leases for equipment rentals.
(2) Consists primarily of future obligations to abandon our leased properties.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISKS

We experience market risks primarily in two areas: interest rates and commodity prices. 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 2004, a 10% decline in the estimated average 2004 prices we receive for our crude oil and natural gas production would have an approximate $6.5 million impact on our revenues.

In 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. 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, 2003, we had entered into the following oil and gas contracts accounted for as cash flow hedges:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
2004	Costless Collar	3,700 MMBtu	$ 4.16 - 6.73
First Quarter 2004	Costless Collar	6,800 MMBtu	$ 4.50 - 7.10
Second Quarter 2004	Costless Collar	4,800 MMBtu	$ 4.50 - 5.53
Third Quarter 2004	Costless Collar	2,300 MMBtu	$ 4.50 - 5.49
2005	Swap	750 MMBtu	$ 4.55
2005	Costless Collar	1,500 MMBtu	$ 4.50 - 5.19
2006	Swap	1,500 MMBtu	$ 4.53
Crude Oil:			
2004	Costless Collar	750 Bbl	$ 25.67 - 29.14
2005	Costless Collar	500 Bbl	$ 23.00 - 26.20
2006	Costless Collar	200 Bbl	$ 23.00 - 26.40

At December 31, 2003, we recognized a liability of $1,561,000 related to these derivative instruments.

As of March 5, 2003, we had entered into the following additional oil and gas contracts accounted for as cash flow hedges:

Production Period	Instrument Type	Daily Volumes		Weighted Average Price
Natural Gas:				
March 2004	Costless Collar	4,000 MMBtu	$	4.50 - 5.71
Second Quarter 2004	Costless Collar	3,500 MMBtu	$	4.50 - 5.73
July - December 2004	Costless Collar	3,000 MMBtu	$	4.50 - 6.26
First Quarter 2005	Costless Collar	3,500 MMBtu	$	4.50 - 7.05
Second Quarter 2005	Costless Collar	2,500 MMBtu	$	4.50 - 5.33
Crude Oil:				
March-December 2004	Costless Collar	250 Bbl	$	26.00 - 33.50

We currently have an interest rate swap covering $5 million of our floating rate debt. The swap which expires in November 2004 has a fixed interest rate of 5.665%. The swap is stated at its fair value and is marked-to-market through derivative expense on our income statement. As of December 31, 2003, the fair value of the open interest rate swap was a liability of $218,000.

We also evaluated the potential effect that reasonably possible near term changes may have on our credit facilities. Debt outstanding under the credit facilities is subject to a floating interest rate and represents 100% of our total debt as of December 31, 2003. Based upon an analysis utilizing the actual interest rate in effect and balances outstanding as of December 31, 2003 and assuming a 10% increase in interest rates and no changes in the amount of debt outstanding, the potential effect on interest expense for 2004 is approximately $157,000.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information concerning this Item begins on page 39.

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, our management carried out an evaluation, with the participation of our principal executive officer (the "CEO") and our principal financial officer (the "CFO"), of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities and Exchange Act of 1934. Based on those evaluations, the CEO and CFO believe:

(i) that our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including the CEO and CFO, as appropriate to allow timely decisions regarding required disclosure; and

(ii) that our disclosure controls and procedures are effective.

Changes in Internal Controls Over Financial Reporting

There have been no significant changes in our internal controls over financial reporting during the period covered by this report that has materially affected, or are reasonably likely to materially affect, our control over financial reporting.

PART III

ITEMS 10, 11, 12, 13 & 14

For information concerning Item 10. Directors and Executive Officers of the Registrant, Item 11. Executive Compensation, Item 12. Security Ownership of Certain Beneficial Owners and Management, Item 13. Certain Relationships and Related Transactions 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 12, 2004, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) 1. FINANCIAL STATEMENTS

The following financial statements of the Company and the Report of the Company's Independent Public Accountants thereon are included on pages 39 through 57 of this Form 10-K:

Report of Independent Auditors
Report of Independent Public Accountants
Consolidated Balance Sheets as of December 31, 2003 and 2002
Consolidated Statements of Operations for the three years ended December 31, 2003
Consolidated Statements of Stockholder's Equity for the three years ended December 31, 2003
Consolidated Statements of Cash Flows for the three years ended December 31, 2003
Notes to Consolidated Financial Statements

2. FINANCIAL STATEMENT SCHEDULES:

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

3. EXHIBITS:

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

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

3.2 Bylaws of the Company (incorporated herein by reference to Exhibit 4.2 to Form 8-K dated September 16, 1998).

3.3 Certificate of Domestication of Optima Petroleum Corporation (incorporated herein by reference to Exhibit 4.4 to Form 8-K dated 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).

4.1 Warrant to Purchase Common Shares of PetroQuest Energy, Inc. (incorporated 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).

10.1 PetroQuest Energy, Inc. 1998 Incentive Plan, as amended and restated effective December 1, 2000 (incorporated herein by reference to Appendix A to Proxy Statement on Schedule 14A filed April 20, 2001).

10.2 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).

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

10.4 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).

10.5	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).
10.6	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).
10.7	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).
10.8	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).
10.9	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).
10.10	Employment Agreement dated September 1, 1998, between PetroQuest Energy, Inc. and Ralph J. Daigle (incorporated herein by reference to Exhibit 10.4 to Form 8-K dated September 16, 1998).
10.11	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)
10.12	First Amendment to Employment Agreement dated September 1, 1998 between PetroQuest Energy, Inc. and Ralph J. Daigle dated July 30, 1999 (incorporated herein by reference to Exhibit 10.3 to Form 8-K dated August 9, 1999).
10.13	Employment Agreement dated May 8, 2000 between PetroQuest Energy, Inc. and Michael O. Aldridge (incorporated by reference to Exhibit 10.1 to the Form 10-Q filed August 14, 2000).
10.14	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).
10.15	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).
10.16	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).
10.17	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).
10.18	Form of Termination Agreement Between PetroQuest Energy, Inc. and each of its executive officers, including Charles T. Goodson, Ralph J. Daigle, 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).
10.19	Form of Indemnification Agreement between PetroQuest Energy, Inc. and each of its directors and executive officers, including Charles T. Goodson, Ralph J. Daigle, 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 and Stephen H. Green (incorporated herein by reference to Exhibit 10.21 to Form 10-K filed March 13, 2002).
*14.1	Business Ethics Policy
21.1	Subsidiaries of the Company (incorporated herein by reference to Exhibit 21.1 to Form 10-K filed March 30, 2001).
*23.1	Consent of Independent Auditors.
23.2	Consent of Arthur Andersen LLP (omitted pursuant to Rule 437a under the Securities Act of 1933, as amended).
*23.3	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.

* Filed herewith.

REPORTS ON FORM 8-K

(i) The Company filed a report on Form 8-K on November 6, 2003, relating to third quarter 2003 results.
(ii) The Company filed a report on Form 8-K on December 29, 2003, relating to the closing of a property acquisition and amendment of credit facilities.

GLOSSARY OF 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. 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 March 12, 2004.

PETROQUEST ENERGY, INC.

By: /s/ Charles T. Goodson
CHARLES T. GOODSON
Chairman of the Board 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 March 12, 2004.

By: /s/ Charles T. Goodson
CHARLES T. GOODSON
Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)

By: /s/ Ralph J. Daigle
RALPH J. DAIGLE
Executive Vice President and Director

By: /s/ Michael O. Aldridge
MICHAEL O. ALDRIDGE
Senior Vice President, Chief Financial Officer, Treasurer and Director (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/ E. Wayne Nordberg
E. WAYNE NORDBERG
Director

By: /s/ William W. Rucks, IV
WILLIAM W. RUCKS, IV
Director

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT AUDITORS

To the Stockholders of
PetroQuest Energy, Inc.:

We have audited the accompanying consolidated balance sheets of PetroQuest Energy, Inc. (a Delaware corporation) as of December 31, 2003 and 2002, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the two years in the period ended December 31, 2003. 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. The financial statements of PetroQuest Energy, Inc. for the year ended December 31, 2001 were audited by other auditors who have ceased operations and whose report dated March 7, 2002, expressed an unqualified opinion on those statements and included an explanatory paragraph that disclosed the change in the Company's method of accounting for derivative instruments and hedging activities discussed in Note 2 to these financial statements.

We conducted our audits in accordance with auditing standards generally accepted in the 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 2003 and 2002 financial statements referred to above present fairly, in all material respects, the consolidated financial position of PetroQuest Energy, Inc. as of December 31, 2003 and 2002, and the consolidated results of its operations and its cash flow for each of the two years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2003 the Company adopted Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations."

/s/ ERNST & YOUNG LLP

New Orleans, Louisiana
March 9, 2004

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Stockholders of
PetroQuest Energy, Inc.:

We have audited the accompanying consolidated balance sheets of PetroQuest Energy, Inc. (a Delaware corporation) and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2001. 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 auditing standards generally accepted in the 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 financial position of PetroQuest Energy, Inc. and subsidiaries as of December 31, 2001 and 2000, and the consolidated results of their operations and their cash flow for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 2 to the consolidated financial statements effective January 1, 2001, the Company adopted SFAS 133, "Accounting for Derivatives Instruments and Hedging Activities."

/s/ ARTHUR ANDERSEN LLP

New Orleans, Louisiana
March 7, 2002

NOTE: The report of Arthur Andersen LLP presented above is a copy of a previously issued Arthur Andersen LLP report and said report has not been reissued by Arthur Andersen LLP nor has Arthur Andersen LLP provided a consent to the inclusion of its report in this Form 10-K.

PETROQUEST ENERGY, INC.
CONSOLIDATED BALANCE SHEETS
(Amounts in Thousands)

	December 31, 2003	December 31, 2002
ASSETS		
Current assets:		
Cash and cash equivalents	$ 779	$ 1,137
Oil and gas revenue receivable	6,520	6,500
Joint interest billing receivable	2,575	2,165
Other current assets	1,005	310
Total current assets	10,879	10,112
Oil and gas properties:		
Oil and gas properties, full cost method	282,898	214,543
Unevaluated oil and gas properties	10,813	15,653
Accumulated depreciation, depletion and amortization	(133,482)	(109,450)
Oil and gas properties, net	160,229	120,746
Other assets, net of accumulated depreciation and amortization of $3,826 and $2,851, respectively	5,276	1,205
Total Assets	$ 176,384	$ 132,063
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 18,126	$ 18,337
Advances from co-owners	2,752	940
Current portion of long-term debt	5,300	6,600
Total current liabilities	26,178	25,877
Long-term debt	22,200	2,400
Asset retirement obligation	12,476	-
Deferred income taxes	7,803	5,461
Other liabilities	-	555
Commitments and contingencies	-	-
Stockholders' equity:		
Common stock, $.001 par value; authorized 75,000 shares; issued and outstanding 44,542 and 42,852 shares, respectively	45	43
Paid-in capital	112,038	106,173
Unearned deferred compensation	(69)	(337)
Other comprehensive income	(1,015)	(1,197)
Accumulated deficit	(3,272)	(6,912)
Total stockholders' equity	107,727	97,770
Total liabilities and stockholders' equity	$ 176,384	$ 132,063

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in Thousands, Except Per Share Data)

	Year Ended December 31,		
	2003	2002	2001
Revenues:			
Oil and gas sales	$ 47,910	$ 48,141	$ 54,967
Interest and other income	778	97	375
	48,688	48,238	55,342
Expenses:			
Lease operating expenses	9,449	9,988	7,172
Production taxes	884	614	1,096
Depreciation, depletion and amortization	27,098	28,196	23,094
General and administrative	4,444	5,009	4,752
Accretion of asset retirement obligation	682	-	-
Interest expense	579	278	2,111
Derivative expense	1,071	558	61
	44,207	44,643	38,286
Income from operations	4,481	3,595	17,056
Income tax expense	1,690	1,288	5,411
Income before cumulative effect of change in accounting principle	$ 2,791	$ 2,307	$ 11,645
Cumulative effect of change in accounting principle	849	-	-
Net income	$ 3,640	$ 2,307	$ 11,645
Earnings per common share:			
Basic			
Income before cumulative effect of change in accounting principle	$ 0.06	$ 0.06	$ 0.37
Cumulative effect of change in accounting principle	0.02	-	-
Net income	$ 0.08	$ 0.06	$ 0.37
Diluted			
Income before cumulative effect of change in accounting principle	$ 0.06	$ 0.06	$ 0.34
Cumulative effect of change in accounting principle	0.02	-	-
Net income	$ 0.08	$ 0.06	$ 0.34
Weighted average number of common shares:			
Basic	43,661	37,871	31,818
Diluted	44,181	39,997	34,271

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(Amounts in Thousands, Except Share Data)

	Common Stock	Paid-In Capital	Unearned Deferred Compensation	Other Comprehensive Income	Accumulated Deficit	Total Stockholders' Equity
December 31, 2000	$ 30	$ 62,290	$ -	$ -	$ (20,864)	$ 41,456
Options and warrants exercised	3	1,510	(1,034)	-	-	479
Amortization of deferred compensation	-	413	352	-	-	765
Tax effect of deferred compensation	-	(130)	-	-	-	(130)
Cumulative effect of change in accounting principle, net of taxes	-	-	-	(383)	-	(383)
Amortization of derivative fair value adjustment	-	-	-	383	-	383
Net income	-	-	-	-	11,645	11,645
December 31, 2001	$ 33	$ 64,083	$ (682)	$ -	$ (9,219)	$ 54,215
Options and warrants exercised	-	178	-	-	-	178
Sale of common stock	10	42,040	-	-	-	42,050
Amortization of deferred compensation	-	-	345	-	-	345
Tax effect of deferred compensation	-	(128)	-	-	-	(128)
Derivative fair value adjustment	-	-	-	(1,197)	-	(1,197)
Net income	-	-	-	-	2,307	2,307
December 31, 2002	$ 43	$ 106,173	$ (337)	$ (1,197)	$ (6,912)	$ 97,770
Options and warrants exercised	2	2,110	-	-	-	2,112
Sale of common stock	-	(6)	-	-	-	(6)
Amortization of deferred compensation	-	-	268	-	-	268
Tax effect of deferred compensation	-	16	-	-	-	16
Warrant fair value adjustment	-	3,745	-	-	-	3,745
Derivative fair value adjustment	-	-	-	182	-	182
Net income	-	-	-	-	3,640	3,640
December 31, 2003	$ 45	$ 112,038	$ (69)	$ (1,015)	$ (3,272)	$ 107,727

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in Thousands)

	Year Ended December 31,		
	2003	2002	2001
Cash flows from operating activities:			
Net income	$ 3,640	$ 2,307	$ 11,645
Adjustments to reconcile net income to net cash provided by operating activities:			
Deferred tax expense	1,690	1,288	5,411
Amortization of debt issuance costs	531	261	1,369
Compensation expense	381	345	765
Depreciation, depletion and amortization	27,098	28,196	23,094
Derivative mark to market	(258)	416	61
Cumulative effect of change in accounting principle	(849)	-	-
Accretion of asset retirement obligation	682	-	-
Plugging and abandonment costs	-	-	(28)
Changes in working capital accounts:			
Accounts receivable	(20)	(918)	(434)
Joint interest billing receivable	(409)	2,443	5,542
Accounts payable and accrued liabilities	1,416	(3,862)	(61)
Other assets	(1,300)	(725)	(1,011)
Advances from co-owners	1,811	(1,376)	(5,253)
Plugging and abandonment escrow	-	1,034	(539)
Other	(1,250)	(231)	308
Net cash provided by operating activities	33,163	29,178	40,869
Cash flows from investing activities:			
Investment in oil and gas properties	(54,126)	(64,324)	(66,678)
Sale of oil and gas properties, net	-	17,321	-
Net cash used in investing activities	(54,126)	(47,003)	(66,678)
Cash flows from financing activities:			
Exercise of options and warrants	2,111	178	671
Proceeds from borrowing	39,600	23,000	28,000
Repayment of debt	(21,100)	(47,329)	(9,348)
Issuance of common stock, net of expenses	(6)	42,050	-
Net cash provided by financing activities	20,605	17,899	19,323
Net increase (decrease) in cash and cash equivalents	(358)	74	(6,486)
Cash and cash equivalents balance beginning of period	1,137	1,063	7,549
Cash and cash equivalents balance end of period	$ 779	$ 1,137	$ 1,063
Supplemental disclosure of cash flow information			
Cash paid during the period from:			
Interest	$ 435	$ 736	$ 1,464
Income taxes	$ -	$ -	$ -

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 – Organization and Summary of Significant Accounting Policies

PetroQuest Energy, Inc. (a Delaware Corporation) ("PetroQuest" or the "Company") is an independent oil and gas company headquartered in Lafayette, Louisiana with an exploration office in Houston, Texas. It is engaged in the exploration, development, acquisition and operation of oil and gas properties onshore and offshore in the Gulf Coast Region.

Principles of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its subsidiaries, PetroQuest Energy, L.L.C. and PetroQuest Oil & Gas, L.L.C. 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. Certain reclassifications of amounts previously reported have been made to conform to current year presentations.

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, restoration, dismantlement and abandonment costs associated therewith, are included in the computation base. The costs of investments in unproved properties are excluded from this calculation until the project is evaluated and proved reserves established or impaired. Oil and gas reserves are estimated annually by independent petroleum engineers. Additionally, the capitalized costs of proved oil and gas properties cannot exceed the present value of the estimated net cash flow from its proved reserves (the full cost ceiling). The Company has adopted a SEC accepted method of calculating the full cost ceiling test whereby the liability recognized under SFAS 143 is netted against property cost and the future abandonment obligations are included in estimated future net cash flows. Transactions involving sales of reserves in place, unless significant, are recorded as adjustments to accumulated depreciation, depletion and amortization.

Upon the acquisition or discovery of oil and gas properties, management estimates the future net costs to be incurred to dismantle, abandon and restore the property using geological, engineering and regulatory data available. Such cost estimates are periodically updated for changes in conditions and requirements. Such estimated amounts are considered as part of the full cost pool for purposes of amortization upon acquisition or discovery. Such costs are capitalized as oil and gas properties as the actual restoration, dismantlement and abandonment activities take place.

In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 141, "Business Combinations," which requires the use of the purchase method of accounting for business combinations initiated after June 30, 2001 and eliminates the pooling-of-interests method. In July 2001, the FASB also issued SFAS No. 142, "Goodwill and Other Intangible Assets," which discontinues the practice of amortizing goodwill and indefinite lived intangible assets and initiates an annual review of impairment. The new standard also requires that, at a minimum, all intangible assets be aggregated and presented as a separate line item in the balance sheet. The adoption of SFAS No. 141 and 142 had no impact on the Company's financial position or results of operations. A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141 and 142 to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires registrants to classify the costs of mineral rights associated with extracting oil and gas as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, the Company has included the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties. These costs include those to acquire contract based drilling and mineral use rights such as delay rentals, lease bonuses, commissions and brokerage fees, and other leasehold costs. If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify these costs as a separate item on the balance sheet, the Company would be required to reclassify approximately $27.5-$28.5 million at December 31, 2003 and approximately $5-$6 million at December 31, 2002. The Company's cash flows and results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with full cost accounting rules, as allowed by SFAS No. 142. Further, the Company believes the classification of the costs of mineral rights associated with extracting oil and gas as intangible assets would have an impact on the Company's compliance with the minimum tangible net worth covenant under its bank credit facility.

PetroQuest will continue to classify its oil and gas leasehold costs as tangible oil and gas properties until further guidance is provided. The Company anticipates there will be no effect on its results of operations or cash flows.

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 loan costs which are amortized over the life of the related loan.

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. 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 where management deems appropriate. 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, 2003, 2002 and 2001 were not significant.

Certain Concentrations

During 2003, 84% of the Company's oil and gas production was sold to five customers. During 2002, 66% of the Company's oil and gas production was sold to three customers. During 2001, 66% of the Company's oil and gas production was sold to four customers. Based on the availability of other customers, the Company does not believe the loss of any of these customers would have a significant financially disruptive effect on its business or financial condition.

Fair Value of Financial Instruments

The fair value of accounts receivable and accounts payable approximate book value at December 31, 2003 and 2002 due to the short-term nature of these accounts. The fair value of the credit facilities approximate book value due to the variable rate of interest charged.

Derivative Instruments

On January 1, 2001, the Company adopted Statement of Financial Accounting Standards No. 133, as amended (SFAS 133) pertaining to the accounting for derivative instruments and hedging activities. SFAS 133 requires an entity to recognize all of its derivatives as either assets or liabilities on its balance sheet and measure those instruments at fair value. If the conditions specified in SFAS 133 are met, those instruments may be designated as hedges. Changes in the value of hedge instruments would not impact earnings, except to the extent that the instrument is not perfectly effective as a hedge.

The Company recognized ($4,462,000), ($861,000) and $1,630,000 in oil and gas revenues during the years ended December 31, 2003, 2002 and 2001, respectively as a result of the settlement of derivatives. The Company recognized $1,071,000, $558,000 and $61,000 in derivative expense during the years ended December 31, 2003, 2002 and 2001, respectively as a result of the settlement of derivatives. As of December 31, 2003, the Company had entered into the following oil and gas contracts accounted for as cash flow hedges:

Production Period	Instrument Type	Daily Volumes		Weighted Average Price
Natural Gas:				
2004	Costless Collar	3,700 MMBtu	$	4.16 - 6.73
First Quarter 2004	Costless Collar	6,800 MMBtu	$	4.50 - 7.10
Second Quarter 2004	Costless Collar	4,800 MMBtu	$	4.50 - 5.53
Third Quarter 2004	Costless Collar	2,300 MMBtu	$	4.50 - 5.49
2005	Swap	750 MMBtu	$	4.55
2005	Costless Collar	1,500 MMBtu	$	4.50 - 5.19
2006	Swap	1,500 MMBtu	$	4.53
Crude Oil:				
2004	Costless Collar	750 Bbl	$	25.67 - 29.14
2005	Costless Collar	500 Bbl	$	23.00 - 26.20
2006	Costless Collar	200 Bbl	$	23.00 - 26.40

At December 31, 2003, the Company recognized a liability of $1,561,000 related to these derivative instruments.

As of March 5, 2003, we had entered into the following additional oil and gas contracts accounted for as cash flow hedges:

Natural Gas:				
March 2004	Costless Collar	4,000 MMBtu	$	4.50 - 5.71
Second Quarter 2004	Costless Collar	3,500 MMBtu	$	4.50 - 5.73
July - December 2004	Costless Collar	3,000 MMBtu	$	.4.50 - 6.26
First Quarter 2005	Costless Collar	3,500 MMBtu	$	4.50 - 7.05
Second Quarter 2005	Costless Collar	2,500 MMBtu	$	4.50 - 5.33
Crude Oil:				
March-December 2004	Costless Collar	250 Bbl	$	26.00 - 33.50

The Company currently has an interest rate swap covering $5 million of our floating rate debt. The swap which expires in 2004 has a fixed interest rate of 5.665%. The swap is stated at its fair value and is marked-to-market through derivative expense on the Company's income statement. As of December 31, 2003, the fair value of the open interest rate swap was a liability of $218,000.

New Accounting Standards

In June 2001, the Financial Accounting Standards Board issued SFAS 143, "Accounting for Asset Retirement Obligations," which requires recording the fair value of an asset retirement obligation associated with tangible long-lived assets in the period incurred. 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 adopted SFAS 143 effective January 1, 2003. The net difference between the Company's previously recorded abandonment liability and the amounts estimated under SFAS 143, after taxes, totaled a gain of $849,000, which has been recognized as a cumulative effect of a change in accounting principle. The gain is due to the effect on the historical depletion as a result of the retirement obligation being recorded at fair value. On a pro forma basis, the impact for the year ended December 31, 2002 would have increased net income by $360,000.

The Company has legal obligations to plug, abandon and dismantle existing wells and facilities that it has acquired and constructed during its existence. As of January 1, 2003, the Company recognized a $9,467,000 liability for its asset retirement obligations and recorded the related additional assets that will be depreciated using the unit-of-production method. The following table describes all changes to the Company's asset retirement obligation liability:

	Year Ended December 31, 2003
Asset retirement obligation at beginning of year	$ -
Liability recognized in transition	9,467,000
Liabilities incurred during 2003	663,000
Liabilities settled during 2003	(389,000)
Accretion expense	682,000
Revisions in estimated cash flows	2,053,000
Asset retirement obligation at end of period	$ 12,476,000

In January 2003, the Financial Accounting Standards Board issued Interpretation No. 46, Consolidation of Variable Interest Entities (FIN 46), which requires companies to evaluate variable interest entities to determine whether to apply the consolidation provisions of FIN 46 to those entities. The consolidation provisions of FIN 46, if applicable, would apply to variable interest entities created after January 31, 2003 immediately, and to variable interest entities created before February 1, 2003 in the Company's interim period beginning October 1, 2003. The Company believes that it has no interests in these types of entities.

Earnings per Common Share Amounts

Basic earnings per common share was computed by dividing net income or loss by the weighted average number of shares of common stock outstanding during the year. 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 considered common stock equivalents computed using the treasury stock method.

Options and warrants to purchase 3,385,334 shares of common stock at $2.29 to $7.65 per share were outstanding during 2003 but were not included in the computation of diluted earnings per share because the options' and warrants' exercise prices were greater than the average market price of the common shares. Options to purchase 273,667 shares of common stock at $5.56 to $7.65 per share were outstanding during 2002 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 180,000 shares of common stock at $5.89 to $7.65 per share were outstanding during 2001 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.

Stock-based Compensation

The Company accounts for its stock-based compensation plans under the principles prescribed by the Accounting Principles Board's Opinion No. 25, "Accounting for Stock Issued to Employees." No stock option compensation cost is reflected in net income, 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. The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of SFAS No. 123, "Accounting for Stock Based Compensation" 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,		
	2003	2002	2001
Net income	$ 3,640	$ 2,307	$ 11,645
Stock-based compensation:			
Add: expense included in reported results, net of tax	248	224	497
Deduct: fair value based method, net of tax	(541)	(904)	(1,260)
Pro forma net income	$ 3,347	$ 1,627	$ 10,882
Earnings per common share			
Basic - as reported	$ 0.08	$ 0.06	$ 0.37
Basic - pro forma	$ 0.08	$ 0.04	$ 0.34
Diluted - as reported	$ 0.08	$ 0.06	$ 0.34
Diluted - pro forma	$ 0.08	$ 0.04	$ 0.32

See Note 10 for the Company's additional disclosures of stock-based compensation under SFAS No. 148.

Note 2 – Acquisition and Disposition of Assets

On December 23, 2003, the Company acquired an interest in the Southeast Carthage Field in East Texas for approximately $23.4 million. The Company allocated approximately $1.2 million of the purchase price to unevaluated acreage. At December 31, 2003, the Company's independent reservoir engineering firm attributed 29 Bcfe of proved reserves net to the Company's interest in this field.

On March 1, 2002, the Company closed the sale of its interest in Valentine Field for $18.6 million. The transaction had an effective date of January 1, 2002. At December 31, 2001, the Company's independent reservoir engineering firm attributed 7.3 Bcfe of proved reserves net to the Company's interest in this field. Consistent with the full cost method of accounting, the Company did not recognize any gain or loss as a result of this sale. The proceeds were treated as a reduction of the full cost pool through an increase in accumulated depreciation, depletion and amortization.

Note 3 – Equity

Other Comprehensive Income

The following table presents a recap of the Company's comprehensive income for years ended December 31, 2003 and 2002 (in thousands):

	Year Ended December 31,	
	2003	2002
Net income	$ 3,640	$ 2,307
Change in fair value of derivative instrument, accounted for as hedges, net of taxes	182	(1,197)
Comprehensive income	$ 3,822	$ 1,110

The Company accounts for derivatives in accordance with Statement of Financial Accounting Standards No. 133, as amended (SFAS 133). When the conditions specified in SFAS 133 are met, the Company may designate these derivatives as hedges. At December 31, 2003 and 2002, the effect of derivative financial instruments is net of deferred income tax benefit of $546,000 and $644,000, respectively.

Unearned Deferred Compensation

In April 2001, the Original Owners of American Explorer L.L.C. entered into an agreement with an officer of the Company whereby the Original Owners granted to the officer an option to acquire, at a fixed price, certain of the original shares the Original Owners were issued in the Merger. As the fixed price of the April grant was below the market price as of the date of grant, the Company is recognizing non-cash compensation expense over the three-year vesting period of the option. In addition, the Original Owners granted to the officer an interest in a portion of the Common Stock issuable pursuant to the Contingent Stock Issue Rights ("CSIRs"), if any, that might be issued. This agreement is similar to agreements previously entered into with two other officers of the Company. Non-cash compensation expense is being recognized for the Common Stock issuable pursuant to the CSIRs granted to the three officers over the three-year vesting period based on the fair value of the Common Stock issuable pursuant to the CSIRs in May 2001, when the Common Stock issuable pursuant to the CSIRs was issued to the Original Owners. The Company has recorded the effects of the transactions as deferred compensation until fully amortized. We recognized $381,000, $345,000 and $765,000, respectively of non-cash compensation expense during the years ended December 31, 2003, 2002 and 2001.

Common Stock Issue Rights

Pursuant to a Company merger, the Company issued to the original owners of American Explorer L.L.C. and their respective affiliates, certain of whom currently serve as officers and directors of the Company, 7,335,001 shares of the Company's common stock, par value $.001 per share (the "Common Stock"), and 1,667,001 CSIRs. The CSIRs entitled the holders to receive an additional 1,667,001 shares of Common Stock at such time within three years of the anniversary date of the issuance of the CSIRs if the trading price for the Common Stock closed at $5.00 or higher for 20 consecutive trading days. On May 3, 2001 the Common Stock closed higher than $5.00 for the twentieth consecutive trading day, and 1,667,001 shares of Common Stock were issued under the terms of the CSIRs.

Note 4 – Debt

The Company entered into a bank credit facility on May 14, 2003. Pursuant to the new credit facility agreement, PetroQuest and our subsidiary PetroQuest Energy, L.L.C. (the "Borrower") have a $75 million revolving credit facility which permits the Borrower to borrow amounts from time to time based on its available borrowing base as determined in the bank credit facility. The bank credit facility is secured by a mortgage on substantially all of the Borrower's oil and gas properties, a pledge of the membership interest of the Borrower and PetroQuest's corporate guarantee of the indebtedness of the Borrower. The borrowing base under the bank credit facility is based upon the valuation as of April 1 and October 1 of each year of the Borrower's mortgaged properties, projected oil and gas prices, and any other factors deemed relevant by the lenders. The Company or the lenders may also request additional borrowing base redeterminations. As of December 31, 2003, the borrowing base under the bank credit facility was $20.2 million and is subject to monthly reductions of $1 million commencing March 1, 2004. The Company has recently completed a borrowing base redetermination as of March 1, 2004, and the borrowing base is $21.2 million and subject to monthly reductions of $1.25 million commencing on July 1, 2004. The banks will determine future monthly reductions in connection with each borrowing base redetermination.

Outstanding balances on the revolving credit facility bear interest at either the bank's prime rate plus a margin (based on a sliding scale of 0.75% to 1.25% based on borrowing base usage but never less than the Federal Funds Effective Rate plus 0.5%) or the Eurodollar rate plus a margin (based on a sliding scale of 2.0% to 2.5% depending on borrowing base usage). The bank credit facility also allows the Company to use up to $5 million of the borrowing base for letters of credit for fees equal to the applicable margin rate for Eurodollar advances. At March 5, 2004, the Company had $15.5 million of borrowings and no letters of credit issued pursuant to the bank credit facility.

The Company is subject to certain restrictive financial and non-financial covenants under the bank credit facility, including a minimum current ratio of 1.0 to 1.0, all as defined in the credit facility agreement. The bank credit facility also requires the Borrower to establish and maintain commodity hedges covering at least 50% of its proved developed producing reserves on a rolling twelve-month basis. As of December 31, 2003, the Company was in compliance with all of the covenants in the bank credit facility. The bank credit facility matures on May 14, 2006.

On November 6, 2003, the Company obtained a $20 million subordinated term credit facility from Macquarie Americas Corp. ("Macquarie"). The sub-debt facility carries an interest rate of prime plus 5.5%, is secured by a second mortgage on substantially all of our oil and gas properties and matures November 30, 2006. The sub-debt facility is available for advances at any time until December 31, 2004 subject to the restrictive covenants of the sub-debt facility and Macquarie approval. At closing, Macquarie received warrants to purchase 1,250,000 shares of our common stock at an exercise price of $2.30 per share. When cumulative advances under the facility exceeded $5 million, $10 million and $15 million, Macquarie was to receive warrants to purchase an additional 250,000 shares, 500,000 shares and 250,000 shares of our common stock, respectively, at the same exercise price per share. In conjunction with the December 23, 2003 property acquisition, the sub-debt facility was amended and the original warrant was cancelled and reissued at which time all 2,250,000 warrants were issued to Macquarie. The warrants are exercisable at any time through the earlier of 36 months following the repayment in full of the sub-debt facility or 30 days after daily volume weighted average price of our common stock as published by Nasdaq is equal to or greater than, for a period of 30 days, the exercise price multiplied by three. In addition, the Company granted Macquarie piggy-back registration rights with respect to the shares of common stock issuable upon exercise of the warrants.

As of December 31, 2003, the Company had $12 million borrowed under the sub-debt facility which was primarily used to fund the acquisition of properties in the Southeast Carthage Field. The sub-debt facility, as amended, contains certain restrictive financial and non-financial covenants, including a minimum current ratio of 1.0 to 1.0, a total debt threshold of $45 million and a cumulative minimum production and net operating cash flow threshold, all as defined in the sub-debt facility. The sub-debt facility also requires the Company to establish and maintain commodity hedges covering at least 65% of its proved developed producing reserves through November 2006. As of December 31, 2003, the Company was in compliance with all of the covenants in the sub-debt facility.

During January 2004, the sub-debt facility, including the note, liens, warrants and all other rights of Macquarie thereunder, was assigned to Macquarie Bank Limited, an affiliate of Macquarie Americas Corp.

Note 5 – Related Party Transactions

Charles T. Goodson, Ralph J. Daigle, Stephen H. Green, or their affiliates, are working interest owners and overriding interest owners and E. Wayne Nordberg is a working interest owner in particular properties operated by us or in which we also hold 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, 2003, in their capacities as working interest owners or overriding royalty interest owners, revenues, net of costs were disbursed to Messrs. Goodson, Daigle, and Green, or their affiliates, in the approximate amounts of $841,350, $481,276, and $107,367, respectively, and with respect to the working interests of Mr. Nordberg, costs exceeded revenues by approximately $89,225. With respect to Messrs. Goodson and Daigle, or their affiliates, gross revenues attributable to interests, properties or participation rights held by them prior to Messrs. Goodson and Daigle joining us as officers and directors on September 1, 1998 represent approximately 94% and 90%, respectively, of the gross revenues received by them in 2003.

Note 6 – Common Stock

During October and November 2002, the Company completed the offering of 5,000,000 shares of its common stock. The shares were sold to the public for $4.25 per share. After underwriting discounts, the Company realized proceeds of approximately $20.4 million.

During February and March 2002, the Company completed the offering of 5,193,600 shares of its common stock. The shares were sold to the public for $4.40 per share. After underwriting discounts, the Company realized proceeds of approximately $21.9 million.

Note 7 – Investment in Oil and Gas Properties

The following table discloses certain financial data relative to the Company's evaluated 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,		
	2003	2002	2001
Acquisition costs:			
Proved	$ 22,679	$ 1,023	$ 11,928
Unproved	1,769	6,052	1,250
Exploration costs	5,170	16,183	7,280
Development costs	21,685	37,247	43,424
Cumulative effect of change in accounting principle costs	8,150	-	-
Other costs	4,062	4,283	3,652
Total costs incurred	$ 63,515	$ 64,788	$ 67,534

Proved acquisition costs, development costs and cumulative effect of change in accounting principle costs for the year ended December 31, 2003 include $362,000, $1,966,000 and $8,150,000, respectively of non-cash property costs related to the adoption of SFAS 143 effective January 1, 2003. See Note 2 for a further discussion of the adoption of this accounting standard.

Other costs for the year ended December 31, 2003 include $3,611,000 and $451,000 of capitalized general and administrative costs and interest costs, respectively. Other costs for the year ended December 31, 2002 include $3,664,000 and $619,000 of capitalized general and administrative costs and interest costs, respectively. Other costs for the year ended December 31, 2001 include $2,651,000 and $1,001,000 of capitalized general and administrative costs and interest costs, respectively.

At December 31, 2003 and 2002, unevaluated oil and gas properties with capitalized costs of $10,813,000 and $15,653,000, respectively, were not subject to depletion. Of the $10,813,000 of unevaluated oil and gas property costs at December 31, 2003, not subject to depletion, $2,372,000 was incurred in 2003, $4,091,000 was incurred in 2002 and $4,350,000 was incurred in prior years. Of the $15,653,000 of unevaluated oil and gas property costs at December 31, 2002, not subject to depletion, $6,730,000 was incurred in 2002, $3,932,000 was incurred in 2001 and $4,991,000 was incurred in prior years. Management expects that these properties will be evaluated over the next one to three years.

Note 8 – 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." An analysis of the Company's deferred taxes follows (amounts in thousands):

	December 31,	
	2003	2002
Net operating loss carryforwards	$ 7,659	$ 13,829
Percentage depletion carryforward	1,341	1,291
Alternative minimum tax credit	4	4
Deferred Compensation	(355)	(258)
Temporary differences:		
Oil and gas properties – full cost	(17,151)	(21,126)
Derivative mark to market	546	644
Compensation expense	153	153
	$ (7,803)	$ (5,463)

For tax reporting purposes, the Company had operating loss carryforwards of $20,590,000 and $37,376,000 at December 31, 2003 and 2002, respectively. If not utilized, such carryforwards would begin expiring in 2009 and would completely expire by the year 2023. The Company had available for tax reporting purposes $3,832,000 in statutory depletion deductions that may be carried forward indefinitely.

Income tax expense for each of the years ended December 31, 2003, 2002 and 2001 (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,		
	2003	2002	2001
Amount computed using the statutory rate	$ 1,568	$ 1,258	$ 5,970
Increase (reduction) in taxes resulting from:			
State & local taxes	99	79	341
Percentage depletion carryforward	(50)	(129)	(720)
Other	73	80	(180)
Income tax expense	$ 1,690	$ 1,288	$ 5,411

Note 9 – Commitments and Contingencies

On December 10, 2003, our wholly owned subsidiary, PetroQuest Energy, L.L.C. ("PetroQuest Energy") entered into a settlement agreement with The Meridian Resource & Exploration LLC relating to the litigation "*PetroQuest Energy, Inc. f/k/a Optima Energy (U.S.) Corp. v. The Meridian Resource & Exploration Company f/k/a Texas Meridian Resources Exploration, Inc.,* bearing Civil Action No. 99-2394 of the United States District Court for the Western District of Louisiana" and "*The Meridian Resource & Exploration Company v. PetroQuest Energy, Inc.,* bearing Docket No. 996192A of the 15th Judicial District Court in and for Lafayette Parish, Louisiana" which related to our Southwest Holmwood property in Calcasieu Parish, Louisiana.

The Company is a party to other 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, which expire on various dates through 2010.

Future minimum lease commitments as of December 31, 2003 under these operating leases are as follows (in thousands):

2004	$ 741
2005	806
2006	744
2007	703
2008	699
Thereafter	1,362
	$ 5,055

Total rent expense under operating leases was approximately $639,000, $577,000 and $411,000 in 2003, 2002 and 2001, respectively.

Note 10 – Employee Benefit Plans

The Company currently has one stock option plan. The stock options generally become exercisable 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.

A summary of the Company's stock options as of December 31, 2003, 2002 and 2001 and changes during the years ended on those dates is presented below:

	Year Ended December 31,					
	2003		2002		2001	
	Number of Options	Wgtd. Avg. Price	Number of Options	Wgtd. Avg. Price	Number of Options	Wgtd. Avg. Price
Outstanding at beginning of year	2,197,353	$ 3.14	2,238,766	$ 2.94	1,861,900	$ 1.92
Granted	150,000	1.94	112,000	6.17	622,500	5.32
Expired/cancelled/forfeitures	(235,253)	3.76	(66,910)	3.75	(14,500)	6.17
Exercised	(42,466)	1.23	(86,503)	1.44	(231,134)	0.89
Outstanding at end of year	2,069,634	3.03	2,197,353	3.14	2,238,766	2.94
Options exercisable at year-end	1,690,371	2.77	1,453,166	2.36	1,030,608	1.64
Options available for future grant	1,359,069		770,208		268,081	
Weighted average fair value of options granted during the year	$ 1.18		$ 3.93		$ 3.18	

The fair value of each option granted during the periods presented is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions: (a) divided yield of 0% (b) expected volatility ranges of 69.90%-73.90%, 74.50%-74.90% and 65.14% - 67.87% in 2003, 2002 and 2001, respectively (c) risk-free interest rate ranges of 2.93% - 3.39%, 4.17% - 4.54% and 4.03% - 5.10% in 2003, 2002 and 2001, respectively, and (d) expected life of five years for all grants.

The following table summarizes information regarding stock options outstanding at December 31, 2003:

Range of Exercise Price	Options Outstanding At 12/31/03	Wgtd. Avg. Remaining Contractual Life	Wgtd. Avg. Exercise Price	Options Exercisable At 12/31/03	Wgtd. Avg. Exercise Price
$0.85 - $0.94	384,300	5 years	$0.89	384,300	$0.89
$1.44 - $2.29	575,000	7.52 years	$1.73	425,000	$1.66
$3.13 - $3.75	562,500	7.11 years	$3.19	542,502	$3.17
$4.25 - $7.65	547,834	8.15 years	$5.71	338,569	$5.64
	2,069,634	7.11 years	$3.03	1,690,371	$2.77

Note 11 – Oil and Gas Reserve Information - Unaudited

The Company's net proved oil and gas reserves at December 31, 2003 have been estimated by independent petroleum consultants in accordance with guidelines established by the Securities and Exchange Commission ("SEC"). Accordingly, the following reserve estimates are based upon existing economic and operating conditions at the respective dates.

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.

The following table (amounts in thousands) 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, 2000	3,115	30,135
Revisions of previous estimates	(522)	(2,631)
Extensions, discoveries and other additions	3,805	14,409
Purchase of producing properties	606	12,170
Sale of producing properties	-	(114)
Production	(791)	(9,025)
Proved reserves as of December 31, 2001	6,213	44,944
Revisions of previous estimates	(1,204)	(8,955)
Extensions, discoveries and other additions	1,438	19,453
Purchase of producing properties	-	-
Sale of producing properties	(260)	(10,540)
Production	(929)	(7,765)
Proved reserves as of December 31, 2002	5,258	37,137
Revisions of previous estimates	(369)	(7,935)
Extensions, discoveries and other additions	83	6,830
Purchase of producing properties	217	28,410
Sale of producing properties	(200)	(1,456)
Production	(744)	(5,193)
Proved reserves as of December 31, 2003	4,245	57,793
Proved developed reserves:		
As of December 31, 2001	3,104	26,847
As of December 31, 2002	4,201	17,409
As of December 31, 2003	3,446	34,655

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,		
	2003	2002	2001
Future cash flows	$ 460,073	$ 337,776	$ 234,736
Future production and development costs	(166,724)	(120,842)	(118,700)
Future income taxes	(53,514)	(36,687)	(18,226)
Future net cash flows	239,835	180,247	97,810
10% annual discount	(64,609)	(40,831)	(22,763)
Standardized measure of discounted future net cash flows	$ 175,226	$ 139,416	$ 75,047

Changes in Standardized Measure

	Year Ended December 31,		
	2003	2002	2001
Standardized measure at beginning of year	$ 139,416	$ 75,047	$ 178,323
Sales and transfers of oil and gas produced, net of production costs	(37,577)	(38,400)	(45,068)
Changes in price, net of future production costs	23,007	78,648	(188,513)
Extensions and discoveries, net of future production and development costs	38,883	83,005	33,067
Changes in estimated future development costs, net of development costs incurred during this period	10,577	19,059	16,333
Revisions of quantity estimates	(35,796)	(56,166)	(7,742)
Accretion of discount	16,605	8,823	25,687
Net change in income taxes	(12,507)	(13,448)	65,361
Purchase of reserves in place	40,605	-	12,730
Sale of reserves in place	(3,802)	(12,899)	(864)
Changes in production rates (timing) and other	(4,185)	(4,253)	(14,267)
Standardized measure at end of year	$ 175,226	$ 139,416	$ 75,047

The weighted average prices of oil and gas used with the above tables at December 31, 2003, 2002 and 2001 were $32.24, $30.44 and $18.49, respectively, per barrel and $6.02, $4.79 and $2.69, respectively, per Mcf. The Company's cash flow amounts include a reduction for estimated plugging and abandonment costs that will also be reflected as a liability on PetroQuest's balance sheet at December 31, 2003, 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
2003:				
Revenues	$ 16,164	$ 9,101	$ 9,857	$ 13,566
Expenses	14,020	10,799	9,628	11,450
Income before cumulative effect of change in accounting principle	$ 2,144	$ (1,698)	$ 229	$ 2,116
Net income (loss)	$ 2,993	$ (1,698)	$ 229	$ 2,116
Earnings per common share:				
Basic				
Income before cumulative effect of change in accounting principle	$ 0.05	$ (0.04)	$ 0.01	$ 0.05
Net income	$ 0.07	$ (0.04)	$ 0.01	$ 0.05
Diluted				
Income before cumulative effect of change in accounting principle	$ 0.05	$ (0.04)	$ 0.01	$ 0.05
Net income	$ 0.07	$ (0.04)	$ 0.01	$ 0.05
2002:				
Revenues	$ 10,497	$ 11,102	$ 11,024	$ 15,057
Expenses	10,861	10,847	10,074	13,591
Net income (loss)	$ (364)	$ 255	$ 950	$ 1,466
Earnings (loss) per share:				
Basic	$ (0.01)	$ 0.01	$ 0.03	$ 0.04
Diluted	$ (0.01)	$ 0.01	$ 0.02	$ 0.03

(1) The above quarterly earnings per share may not total to the full year per share amount, as the weighted average number of shares outstanding for each quarter fluctuated as a result of the assumed exercise of stock options.

Exhibit 23.1

CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in the Registration Statements (File Nos. 333-67578, 333-63920, 333-52700, 333-42520, 333-65401, 333-102758, 333-88846 and 333-89961) of PetroQuest Energy, Inc., of our report dated March 9, 2004, with respect to the 2003 and 2002 consolidated financial statements of PetroQuest Energy, Inc. included in Form 10-K for the year ended December 31, 2003.

/s/ Ernst & Young LLP
New Orleans, Louisiana
March 11, 2004

Exhibit 23.3

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, 2003, and to the incorporation by reference thereof into the Company's previously filed Registration Statements on Form S-3 and Form S-8, 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, 2001, 2002 and 2003. 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
March 11, 2004

Exhibit 31.1

I, Charles T. Goodson, certify that:

1. I have reviewed this annual report on 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)) 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) 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

   (c) 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
March 12, 2004

Exhibit 31.2

I, Michael O. Aldridge, certify that:

1. I have reviewed this annual report on 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)) 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) 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

   (c) 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/ Michael O. Aldridge
Michael O. Aldridge
Chief Financial Officer
March 12, 2004

Exhibit 32.1

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of PetroQuest Energy, Inc. (the "Company") on Form 10-K for the period ending December 31, 2003 (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
March 12, 2004

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

Exhibit 32.2

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of PetroQuest Energy, Inc. (the "Company") on Form 10-K for the period ending December 31, 2003 (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
March 12, 2004

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 and
Chief Executive Officer
PetroQuest Energy, Inc.

Ralph J. Daigle
Executive Vice President
PetroQuest Energy, Inc.

Michael O. Aldridge
Senior Vice President and
Chief Financial Officer
PetroQuest Energy, Inc.

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

Michael L. Finch *#^
Private Investments

E. Wayne Nordberg *#^
Ingalls & Snyder, LLC

William W. Rucks, IV *#^
Private Investments

* – Member of the Compensation Committee
\# – Member of the Audit Committee
^ – Member of the Nominating & Corporate Governance Committee

Senior Management

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

Ralph J. Daigle
Executive Vice President

Michael O. Aldridge
Senior Vice President and
Chief Financial Officer

Art M. Mixon
Senior Vice President – Operations

Daniel G. Fournerat
Senior Vice President, General Counsel and Secretary

Dalton F. Smith III
Senior Vice President – Business Development and Land

Stephen H. Green
Senior Vice President – Exploration

Robert R. Brooksher
Vice President – Corporate Communications

James S. Blair
Vice President – Business Development

Corporate Address

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

Exploration Office

PetroQuest Energy, Inc.
450 Gears Road, Suite 330
Houston, Texas 77067
Tel: (713) 784-8300
Fax: (713) 784-8327

Transfer Agent and Registrar

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

Independent Auditors

Ernst & Young LLP
New Orleans, Louisiana 70170

Legal Counsel

Onebane, Bernard, Torian, Diaz,
McNamara & Abell
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 a.m. on May 12, 2004 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.

Common Stock Listing

PQUE
NASDAQ
LISTED

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