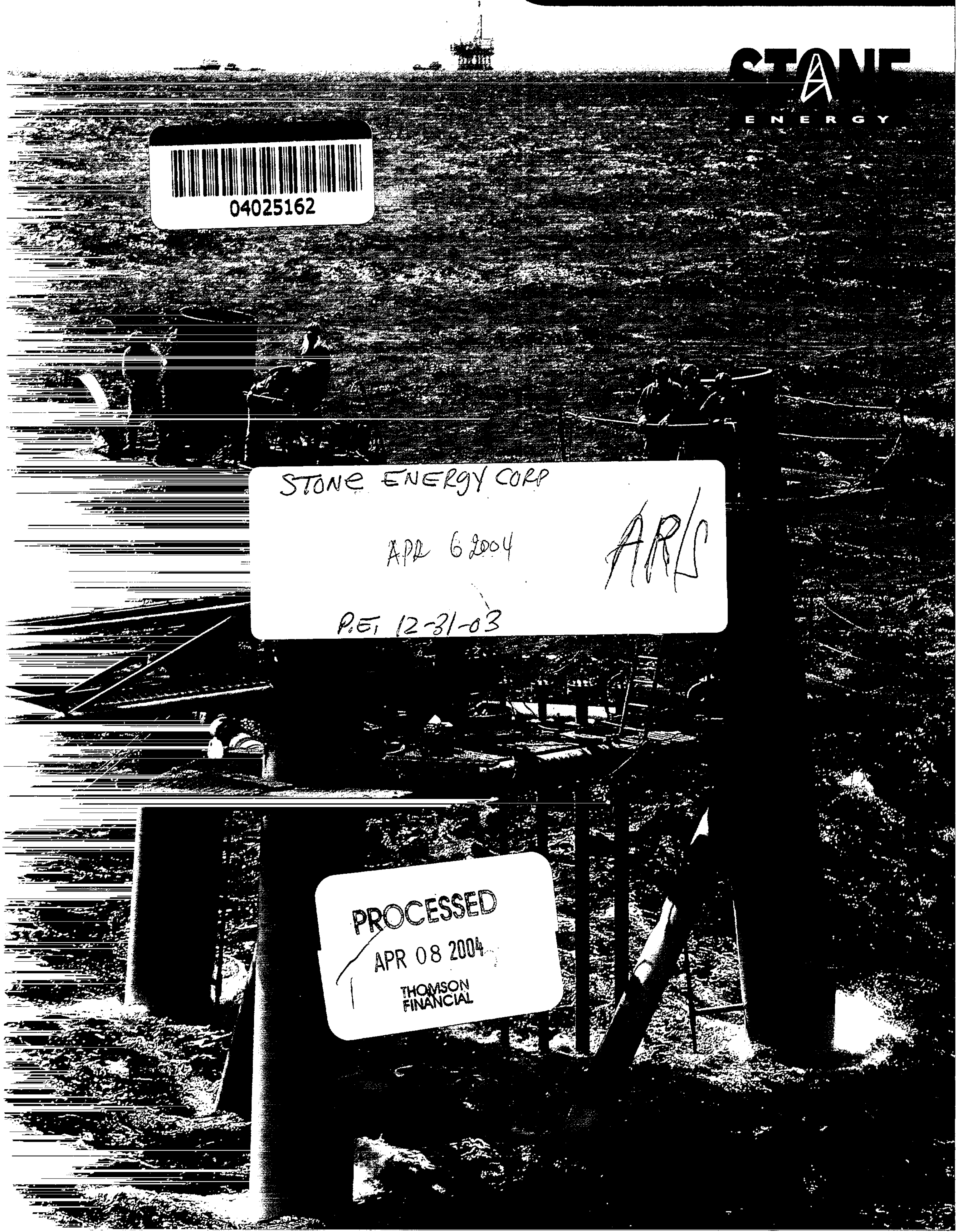
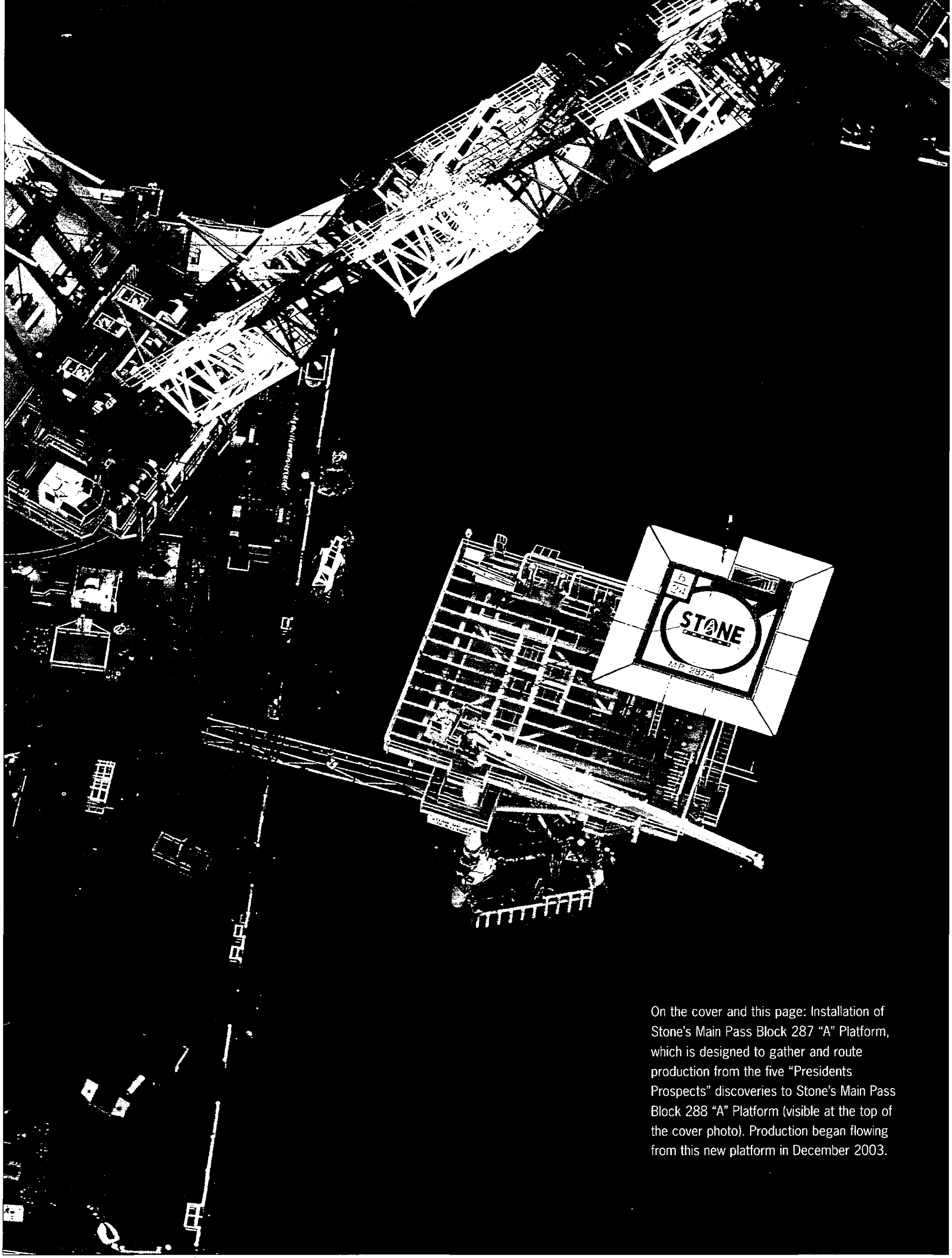
DELIVERING VALUE — 2003 ANNUAL REPORT

STONE ENERGY

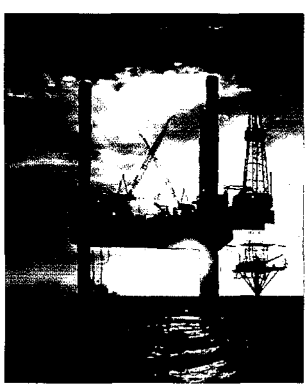
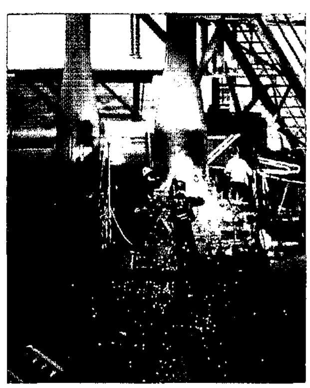
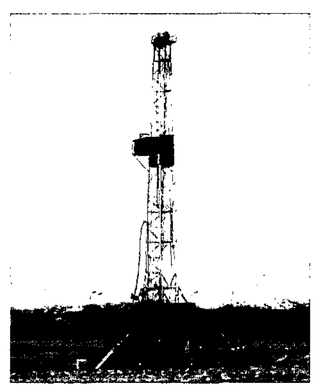




On the cover and this page: Installation of Stone's Main Pass Block 287 "A" Platform, which is designed to gather and route production from the five "Presidents Prospects" discoveries to Stone's Main Pass Block 288 "A" Platform (visible at the top of the cover photo). Production began flowing from this new platform in December 2003.

2003 Highlights

- Drilling success rate of 85% on 44 producers of 52 wells drilled, including 63% success on exploratory wells drilled below 15,000 feet.
- Total proved reserves grew 9% to 816 Bcfe, replacing 167% of our production. Record reserve additions from drilling of approximately 140 Bcfe.
- Reduced finding costs through drilling success and strategic acquisitions.
- Generated record levels of cash flow and net income from record oil and natural gas revenue of $508.3 million.
- Enhanced financial flexibility through the redemption of our $100 million 8¾% Senior Subordinate Notes. Lowered debt level by $61 million.
- Recognized by the Minerals Management Service as one of five 2003 SAFE Award Finalists for "High Activity Operators" in the Gulf of Mexico.
- Established a technical team to evaluate opportunities in the deep water of the Gulf of Mexico.

Operational & Financial Performance

Year Ended December 31,

	2003	2002	2001	2000	1999
PRODUCTION					
Oil (MBbls)	**5,727**	6,237	4,023	4,449	4,324
Gas (MMcf)	**62,536**	67,027	68,236	72,239	65,513
Oil and Gas (MMcfe)	**96,898**	104,449	92,374	98,933	91,457
AVERAGE SALES PRICES [1]					
Oil (per Bbl)	**$ 30.41**	$ 25.00	$ 25.62	$ 26.66	$ 16.19
Gas (per Mcf)	**5.34**	3.31	4.29	3.64	2.27
Oil and Gas (per Mcfe)	**5.25**	3.61	4.28	3.86	2.39
ESTIMATED PROVED RESERVES					
Oil (MBbls)	**59,162**	52,019	55,391	33,625	35,213
Gas (MMcf)	**461,323**	438,652	442,669	398,524	385,667
Oil and Gas (MMcfe)	**816,295**	750,766	775,015	600,274	596,945
Present Value of Estimated Future Pre-Tax Net Cash Flows (in thousands)	**$2,380,259**	$ 1,784,761	$ 1,038,797	$ 2,941,790	$ 830,606

(amounts in thousands, except per share data)					
Total Oil & Gas Revenue [1]	**$ 508,305**	$ 377,495	$ 395,499	$ 381,938	$ 218,415
Net Income (Loss) [2]	**134,470**	55,399	(71,375)	126,457	37,066
Per Diluted Share [2]	**5.07**	2.09	(2.73)	4.80	1.58
Net Cash Flow from Operating Activities	**391,539**	222,921	315,617	302,082	123,010
Oil and Gas Properties, net [2]	**1,317,933**	1,047,936	993,906	747,574	587,661
Total Assets [2]	**1,434,277**	1,179,371	1,101,783	944,104	706,958
Long-Term Debt	**370,000**	431,000	426,000	148,000	134,000
Stockholders' Equity [2]	**710,277**	577,488	530,025	587,577	452,870
Weighted Average Shares Outstanding—Diluted	**26,546**	26,494	26,111	26,335	23,416

[1] Includes the settlement of hedging contracts.

[2] *Includes a $237.7 million reduction in the carrying value of oil and gas properties during 2001.*

Dear Fellow Shareholders,

As I write this letter characterizing what Stone is about, I reflect on how we have progressed over the past decade. Our goal has been to build on our capacity to imagine and achieve success, and that goal has no finish line. Today we have before us the largest opportunity set we have ever encountered. While still a small company by many standards, we believe that we are limited in growth potential only by our own creativity and our ability to share our vision and culture with like-minded investors.

The year 2003 marked our first decade as a publicly traded company, and it is gratifying that it was a year of marked accomplishments and success for Stone. Highlights included an affirmation of our focus in the Gulf Coast Basin where we made five deep shelf exploratory discoveries, each of which will lead to further development and value extraction. We achieved a 63% success rate in drilling these exploratory tests. Our drilling program achieved an overall success rate of 85% with 44 completions in 52 tests. The program yielded a 167% reserve replacement ratio and grew the Company reserve base by 9% to a current volume of 816.3 billion cubic feet of natural gas equivalents. This growth came principally through drilling our ideas rather than buying reserves in a high price environment. We are proud of these numbers.

D. Peter Canty, *President and Chief Executive Officer*

In 2003, we generated record-setting revenue of $508.3 million and reduced our debt by $61.0 million, resulting in a year-end debt to book capitalization ratio of 34%. Independent of commodity pricing that helped all energy companies, we grew our proved reserves per share by 8% to 30.9 Mcfe per share and reduced our debt per Mcfe by 21% to $0.45 per Mcfe. These numbers speak to a solid enterprise succeeding in a time of high energy prices. However, these results do not shed light on the Company's ability to repeat similar results in the future or in unstable pricing cycles. Let me speak to our ability to reinvest successfully in changing price cycles.

As a buyer of mature properties seeking to drill unrecognized value, Stone has had its greatest success in down price cycles when competitors are hard-pressed to make profits from buying cash flow streams rather than identified undrilled potential. To the benefit of our shareholders, Stone Energy has grown consistently over the past decade. This growth has been guided by a clear understanding of our business focus and our assignment, which has been, and continues to be, to increase shareholder value through growing a strong company. Our principal area of business is the Gulf of Mexico. Over 10 years, what started out as 46 employees managing five properties has grown to over 200 employees working on over 100 properties at year-end 2003. Many of these talented people have come to Stone because of the consistency of our technically oriented strategy, strong ethics and culture. They provide a depth of creativity and expertise that not only is responsible for last year's results, but also grew our inventory of drillable prospects last year by 19%. With no additional growth, our current inventory of prospects represents over seven years' worth of drilling at current investment levels.

All of the value we add springs from the minds of the people at Stone. Geoscientists and engineers work daily to add new value potential to our inventory. Our "widgets" are the oil and gas we find, principally in properties where others have looked before and where, through the application of solid practices and new technology, our people have recognized value in places previously overlooked. Clearly, the cost of this process grows with our success because it is a far greater challenge to manage and sustain the growth of a large company than a small one. Offsetting this challenge is the Company's market capitalization of more than $1.2 billion at this writing, thus giving us access to growth arenas that we could only imagine 10 years ago.

We continue to focus our program and the majority of our investments on properties with potential at great depths beneath the shallow waters of the Gulf of Mexico, a producing region that in the past few years has gone in and out of favor with industry analysts. Our results in 2003 confirm our belief that this arena is still the place to play. The reason for Stone's persistence is the proven technical capacity of this basin to continue to yield large discoveries. Unlike other established producing provinces, the greatest treasure of the Gulf Coast Basin continues to be that large discoveries of oil and gas are being recorded at increasingly greater depths without loss of flow rate or product quality. As our ability to both image and drill to ever greater depths continues to grow, our imagination of new targets has kept pace. On the shallow water shelf of the Gulf of Mexico, the infrastructure put in place to recover now depleted reserves can be reused to reduce the investment associated with new deeper drilling. The platforms, wells, pipelines and other "iron" that other players may consider as a liability we view as a potential asset, as we do the acreage that covers both the established large reserves and the prospects beneath that remain to be tested.

Stone Energy Corporation is an independent oil and natural gas company active primarily in the Gulf Coast Basin since 1993, having established extensive geological, geophysical, technical and operational expertise in this area. Our business strategy, which has remained consistent, is to increase reserves, production and cash flow through the acquisition, exploitation and development of mature properties. Our property portfolio consists of 60 active properties and 28 primary term leases in the Gulf Coast Basin, and 33 active properties in the Rocky Mountains.

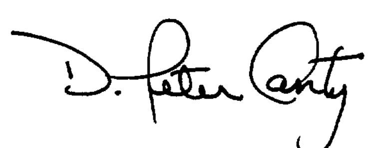
During 2001, Stone established a position in the Rocky Mountains that we have continued to grow as a balancing contributor. The longer producing life of the region and the high completion rate of new wells act as a hedge to the high reinvestment rate of the Gulf of Mexico, albeit at lower profitability. Our focus in the Rockies has been on reserves that, in order to be economically produced, require the evolving technology of massive hydraulic fracturing. This has allowed us to drill new discoveries with economic flow rates in areas not previously developed.

During the past two years, we have concentrated on acquiring the experience and talent necessary to compete in the deep water environment of the Gulf of Mexico. Using the criteria that has worked for us in shallower waters, we have invested in prospects with accessible infrastructure, multiple objective reservoirs, established production history and clear growth potential. With an experienced technical team assembled, we plan to invest in deep water prospects with proportional risk and reward during 2004. For Stone, this is a new and significant area of opportunity that with time will become an increasingly larger portion of our budget. While capital risks are significant, the success of a single prospect in the deep water environment could potentially replace annual production volumes with new reserves.

As you may be aware, I have announced my retirement as CEO of Stone; however, I will maintain a role as a director. As I end my tenure as CEO and 23 years of employment, I wish to welcome David Welch into the Stone family. David is a leader whom I have long respected, who comes to Stone with many years of experience and achievement in the oil and gas industry. Under our new leadership, I believe Stone will undoubtedly continue to grow, and I feel that we are in capable hands.

I am proud of the hard work and dedication exhibited by the our employees in helping to achieve these results and further the growth of our Company. To those who are considering ownership in the Company, we pledge to continue our efforts to consistently grow shareholder value. To those shareholders who have participated with us, I extend my appreciation and thank you for your confidence in our Company.

Sincerely,



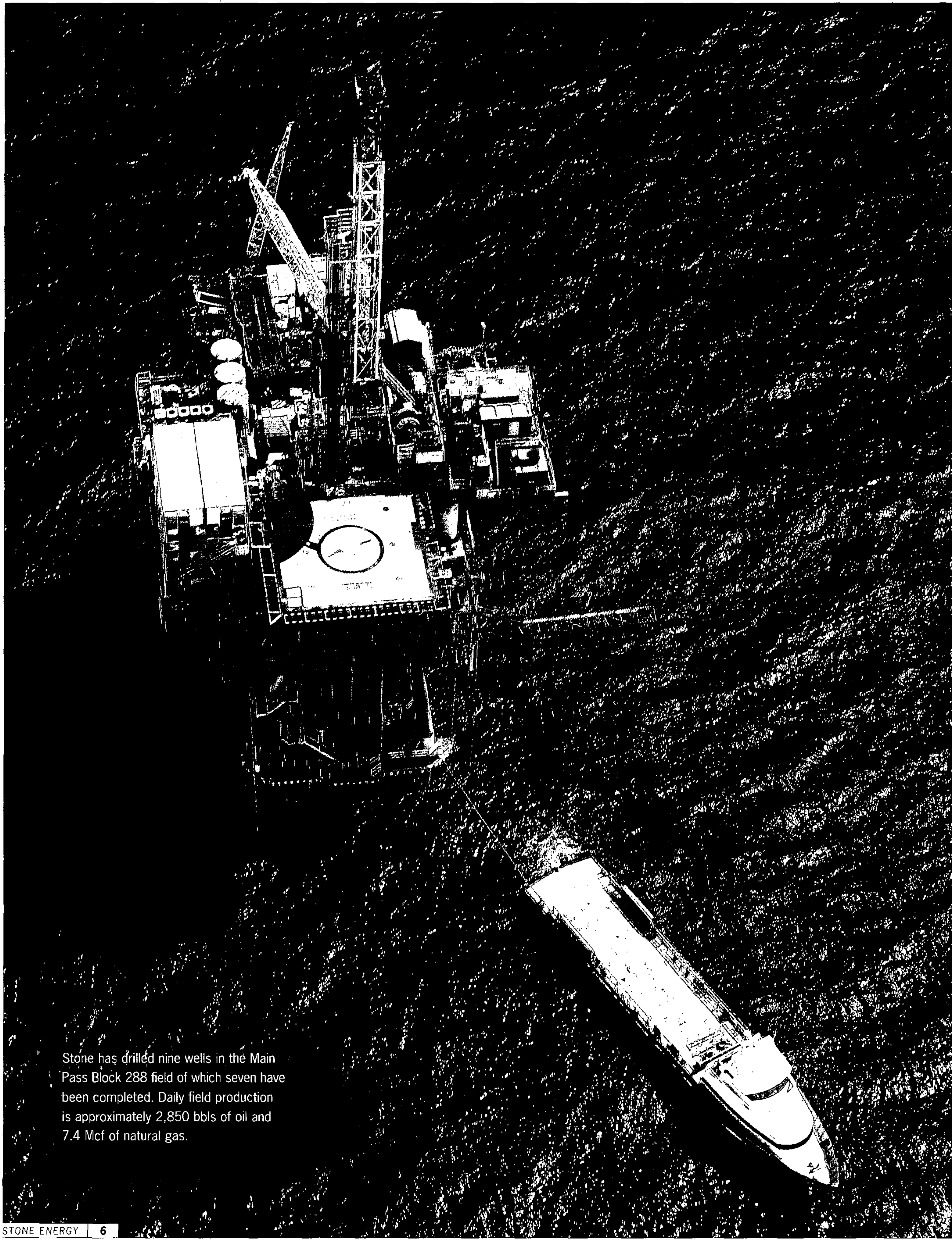
D. Peter Canty
President and Chief Executive Officer

Our Gulf Coast properties are located primarily onshore Louisiana and in the Gulf of Mexico. Our Rocky Mountain properties are located primarily in five basins located in Montana, Wyoming and Utah.

■ 60 GCB Active Properties
33 Rockies Active Properties
93 Total SGY Active Properties

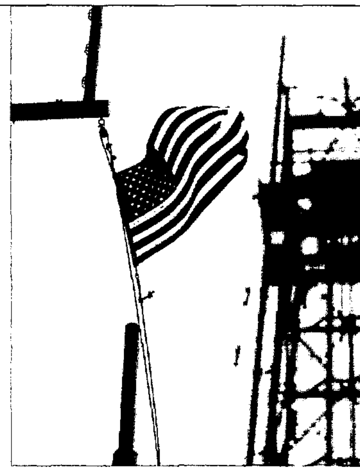
■ 20 Non-Oper. GCB Active Properties
18 Non-Oper. Rockies Active Properties
38 Total Non-Oper. Active Properties

△ 28 GCB Primary Term Leases



Stone has drilled nine wells in the Main Pass Block 288 field of which seven have been completed. Daily field production is approximately 2,850 bbls of oil and 7.4 Mcf of natural gas.

We strive to balance the risks and rewards in the Gulf of Mexico through increased activity in the shallow waters and in the deep shelf.



The Gulf of Mexico (GOM) remains the primary focal area for Stone, accounting for 94% and 91% of our 2003 production and year-end reserves, respectively. We invested approximately 69% of our capital spending in exploratory and development drilling operations on our GOM properties during 2003. Of our 60 active properties in the Gulf Coast Basin, we operate 40 properties, which allows us to control spending, technical analysis and timing of operations.

Managing risks is an important aspect of our business. One of our goals is to design a drilling program that creates a balance of lower-risk, modest-potential wells in our core area with higher-risk, high-potential wells in the shallow water deep shelf and in the deep water of the GOM. Our 2003 drilling success rate of 77% on 24 of 31 exploratory tests is a testament to the overall success of our drilling program. More importantly, we were successful on five of eight attempts on exploratory prospects below 15,000 feet in the GOM. This success is attributed to the meticulous approach of our geoscientists in their technical evaluation of these prospects using evolving technology.

Our capital spending for 2003 was centered on multi-well field projects at Main Pass Block 288, Mississippi Canyon Block 109 and Ewing Bank Block 305. The success in each of these fields is illustrated in the table below.

Commodity prices for oil and natural gas were favorable throughout 2003, resulting in record revenue of over half a billion dollars. During the year, we sold our production for an average of $30.41 per barrel of oil and $5.34 per Mcf of natural gas. These price realizations generated over $391 million of cash flow, which funded our capital expenditures program and allowed us to repay $61 million of debt.

Our 2004 capital spending budget is currently $280 million, which we expect to fund from cash flow based on our outlook of commodity prices and our estimated production. In order to ensure a minimum level of cash flow, we entered into put contracts for a portion of our GOM production to guarantee oil prices of $25.00 per barrel and gas prices of $3.50 per MMBtu in the event market prices fall below these levels. Our $350 million bank credit facility, of which $158 million was available at March 1, 2004, provides sufficient capital to fund potential acquisitions and support our capital spending program.

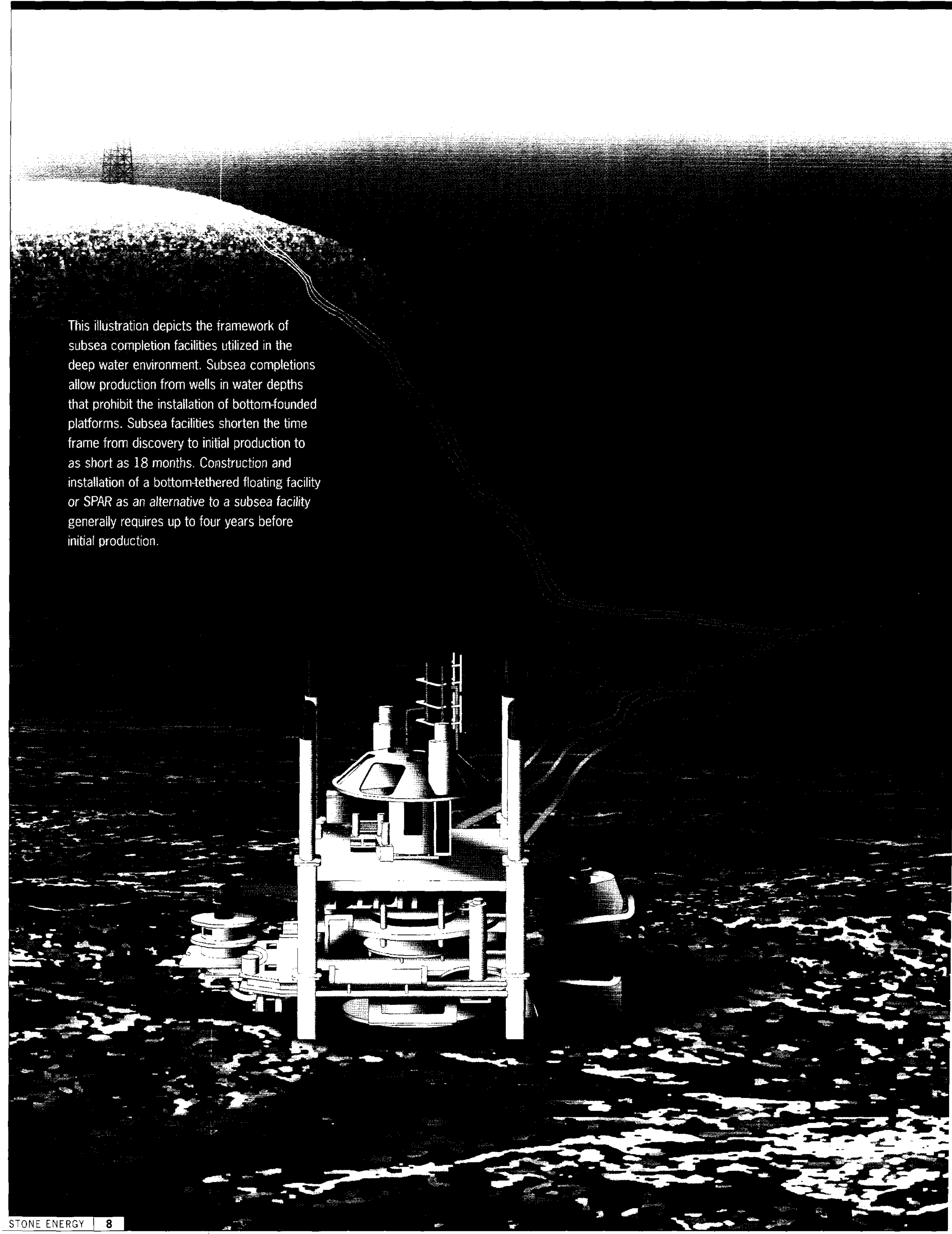
Deep Shelf Success

In 2003, Stone achieved outstanding success in the "deep shelf"— prospects 15,000 feet or more below the sea floor of the GOM's Outer Continental Shelf. The deep shelf represents a relatively new oil and gas play considering the low number of wells drilled on the shelf below 15,000 feet. Drilling deep shelf wells presents complex challenges for explorationists with respect to hydrocarbon imaging and negotiating high-pressured rocks while drilling to targets.

The Minerals Management Service (MMS) has provided an incentive to encourage deep shelf drilling by proposing royalty relief on production from wells below certain depths. This provides a clear indication that the MMS shares our belief that there is a significant amount of reserves to be proven in the deep shelf. For 2004, we have designed a drilling program for the GOM that combines traditional shelf drilling with six high-risk, high-potential prospects in the deep shelf. Additional exploratory exposure is expected to come from our newly formed deep water team.

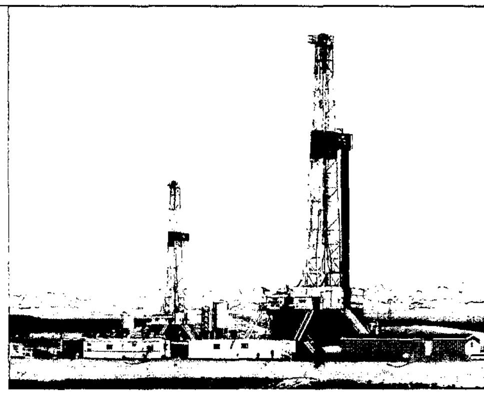
	2003				2004*	
Field	Wells	Workovers	Success Rate	New Platforms	Wells	Workovers
Main Pass Block 288 Field	8	–	100%	1	5	–
Mississippi Canyon Block 109 Field	3	3	100%	–	6	–
Ewing Bank Block 305 Field	2	5	100%	–	5	6

*Based on current budget.



This illustration depicts the framework of subsea completion facilities utilized in the deep water environment. Subsea completions allow production from wells in water depths that prohibit the installation of bottom-founded platforms. Subsea facilities shorten the time frame from discovery to initial production to as short as 18 months. Construction and installation of a bottom-tethered floating facility or SPAR as an alternative to a subsea facility generally requires up to four years before initial production.

We are broadening our scope of exploration with deep water drilling while continuing to exploit opportunities to increase production and reserves from our Rocky Mountain properties.



Deep Water

Stone made the commitment to diversify into deep water exploration in the Gulf of Mexico during 2002. Understanding that the application of Gulf of Mexico shelf experience might not translate to the deep water, we made it our first step to assemble a deep water team of individuals with geological, geophysical and engineering experience in this region to evaluate potential opportunities.

As a non-operator, we have participated to date in wells drilled in water depths to nearly 1,200 feet. Our deep water activity is expected to explore for prospects in water over twice this depth. On some occasions, wells in these water depths require subsea completions (operations that are performed on the seafloor—see opposite page). The advantage of a subsea completion is that production is tied by flow and control lines to a nearby, existing facility without requiring fabrication and installation of costly surface equipment such as a bottom-founded production platform. In most cases, subsea facilities provide more attractive rates of return on investment dollars when compared to the alternative.

Another challenge to the deep water is selecting the best prospect opportunities available with proven operators. Our team looks for opportunities with established deep water players with a good track record. We continue to gain valuable experience on the intricacies of the deep water by working with other operators. For the second half of 2004, we have already committed to participate with a 50% working interest in a well to be drilled in 3,900 feet of water.

Our capital spending budgeted for 2004 includes certain deep water projects; however, we maintain a flexible budget in order to facilitate further drilling in the deep water as projects are presented. We expect our annual investment in the deep water to grow as we evaluate attractive opportunities to participate, as well as opportunities to operate deep water properties when the time is right.

Rocky Mountains

Our February 2001 merger with Basin Exploration more than doubled our producing properties in the Gulf Coast Basin, increased our exploratory lease acreage from approximately 88,000 to 365,000 acres, enhanced our inventory of prospects and diversified our geographically concentrated asset base with an entry into the Rocky Mountain region.

The Rockies properties afforded us the opportunity to offset the steep production declines of the Gulf Coast Basin reservoirs with the lower-risk, longer-life reserves in the Rocky Mountains. Although currently less than 10% of total company production and reserves, the Rockies properties experienced substantial growth in 2003. Stone considers the assets in the Rockies important to the continued growth in shareholder value and has stepped up our investments in this region.

During 2003, Stone invested in nine new wells in the Jonah Field and Pinedale Anticline in the Greater Green River Basin of Wyoming. We are a 50% partner in 19,000 acres on the Pinedale Anticline where we have identified numerous locations for future wells that are direct offsets to productive wells with 40-acre spacing. Stone is also currently active in the Howard Ranch Field in the northern Wind River Basin of Wyoming where we hold approximately 8,400 acres. Most recently, the Company acquired approximately 47,000 net acres of deep rights below the Monument Butte Field in the Uinta Basin of Utah. There is extensive ongoing industry activity in areas around this acreage block.

Stone not only is committed to further development of current properties in the Rockies but continues to pursue acquisitions that meet Stone's strategic profile. The current property base in the Rocky Mountain region gives the company a solid foundation for growth through its inventory of prospects and the quality employees who generate ideas and implement strategy. Stone expects to spend approximately 14% of our total capital budget in exploratory and development activities in the Rocky Mountains during 2004, excluding possible acquisitions.

An Interview with Jimmy Stone, Founder and Chairman of Stone Energy Corporation

on how Stone became Stone, why the culture of the Stone Family is so unique, and how the Company works to protect and grow shareholder value...

Q: Where did you grow up and where are you from originally?

A: I grew up in the East. My mother died when I was quite young so my father raised my two brothers and myself. We all were in the service. My dad was a Commander in the Navy. Donnie was with Patton in Europe and Bobby flew for the Army/Air Force in Europe. I went into the Marine Corps when I was 17 years old and was commissioned at 19. My older brother, Bobby, became a Vice President of the Coca-Cola Company, and my middle brother, Donnie, was the Vice Chairman of the New York Stock Exchange. I'm happy to say we're all in good health; I'm 78, Donnie is 80 and Bobby is 82.

James H. Stone, *Chairman of the Board*

Q: How did you become involved in the oil and gas industry?

A: I graduated from Williams College in Williamstown, Massachusetts, did my geology studies at Texas A&M and then accepted my first job in 1951 with Callory & Hurt, which was an independent in Houston. I lived in Houston for a while before I was called back into the Marine Corps for a second tour during the Korean War. After the war, I continued actively in the business as a geologist.

Q: How did the formation of Stone Energy come about?

A: I founded the Stone Oil Company in 1952 and that same year I found a prospect called "West Poison Spider" in the Natrona County of Wyoming. It became one of the big fields out there and I sold a half interest to the Union Oil Company of California. Between 1952 and 1993, I raised over a billion dollars from partners to drill for oil and gas across the U.S. We had partners who put in half a million dollars, which in those days was a lot of money. In 1993, we went to all of our partners and offered them the opportunity to exchange their property interests for Stone Energy common stock. We always remembered our partners. If we benefited, they benefited.

Q: How has the business changed since your career began?

A: Well, when I started, you could make a deal with somebody and it was as good as done. Today, no deals are done without lawyers. There were a lot more opportunities early on. It was long before we had geophysics. West Poison Spider, for example, was a surface feature. The independents could get started with a cup of coffee back then. You need a 3-D staff to get going today. We really branched into the Gulf Coast as a company in the early '70's. We were considered deep drillers in those days and we're considered deep explorers today. I believe that through the 1990's Stone was No. 2 in the Gulf of Mexico for average well depth drilled.

Q: Looking back, what was your most challenging time or event in the business?

A: The biggest challenge was back in the '80's when the natural gas market collapsed. We had what were called "take or pay" contracts with the gas companies and basically they reneged on them. Of course, we had borrowed to drill wells to produce gas under signed contracts to the gas pipeline companies and we owed the banks that money. That put us in a terrible position because we had relied on those companies to honor their contracts, which they didn't. Fortunately, we were able to get through that period.

Q: What makes Stone Energy different from other companies in the E&P industry?

A: I think it goes back to what we consider our core values. As long as I've worked here, everybody works together. Everyone is a stockholder. I think we're here because we enjoy what we're doing and we enjoy our associates. Our management and the people here have longer tenures than any company I know. And that all goes back to the same thing—we operate as a family.

Q: What has brought you the greatest satisfaction from working with Stone Energy?

A: Three things come to mind. First, we brought together such a great team of people and we made a point of getting to know them and their families. Second is what our team has achieved. We've become a sizable player in our industry. We're listed on the New York Stock Exchange. The Company is worth over a billion dollars. This was all done starting with minimal capital but a strong commitment and a deep knowledge base in the Gulf Coast. Third, probably the smartest thing we ever did was to get Pete Canty as our CEO. Pete came to us from Exxon and he has been responsible for the growth of this Company in a big way. At the time, Pete was a District Geologist for Exxon. Besides being technically capable, Pete is a great people-person and he was able to encourage others to work for Stone. When you ask somebody to leave the so-called security of a big company, you have to offer them a vision. Pete sold these people on that vision and it has become reality.

Q: Why did you choose the Gulf Coast Basin on which to build the Company?

A: The geology of the rocks in the Illinois Basin of Wyoming, where I started, was quite different from the rocks in the Gulf Coast. The quality of the rocks found in the Gulf Coast Basin creates an opportunity for fast production, which returns your money faster. The Gulf Coast Basin was becoming an attractive region in those days because of its reserve potential. The move to this region turned out well for us because of our discovery at Week Island, for which Joe Klutts is responsible.

Q: Stone has recently added the Rocky Mountains and deep water as exploratory areas. What effect does this have on the outlook for Stone Energy?

A: I think this gives us great balance and potential. One of the virtues of the Gulf of Mexico is that your wells produce very quickly. So with good commodity markets, we're able to produce these reserves with high rates of return. On the other hand, the Rocky Mountain reservoirs provide long-lived reserves that balance the steep declines of the Gulf reservoirs, while the deep water provides larger reserve potential to continue Stone's growth.

Q: How is the board of directors active in the business of Stone Energy?

A: We have, I think, one of the most active and best boards of any company that I am familiar with in business. Our board brings a broad experience background to the table. Our most recent addition to the board is Ron Christmas, a retired Marine General who ran a truly large organization as a "no nonsense" business for the Marine Corps. The experience these individuals possess helps us anticipate opportunities and problems, and properly navigate a consistent growth course. They're shareholders and act in the interest of all the shareholders.

Q: With so much concern over corporate governance, how is Stone's management effective in serving the interests of its shareholders?

A: If you take a look at how this Company is run and look at our 10-K, you will see that we were already doing the things mandated by the Sarbannes-Oxley Act of 2002. Our pay structure from top to bottom is modest. The Company is run for the benefit of the shareholders. This is somewhat self-serving as we are all shareholders. It costs a lot of money to pay the auditors and lawyers, but the idea behind it is sound and it is something we've done since day one. Investor confidence is built up by performance over the years. We are proud that many of our shareholders are friends and former partners who have invested with us for over 30 years, first as limited partners and later as shareholders. These are sophisticated people who have stayed with us because we have made them money.

Q: What message do you have for current and potential shareholders about Stone Energy?

A: I would say take a look at the past 30 years of how we've operated. This Company was listed on the New York Stock Exchange in 1993. Take a look at the compounded growth rate of the Company's value since that time. I think in the future we will be able to continue that same growth, hopefully even better growth. Everybody in this Company is focused on shareholder value. At the end of the day, what we will gain for the people who work here and for the people who own the shares is increased value of their assets.

Corporate Information

Back row from left to right:
George R. Christmas,
Joe R. Klutts,
Richard A. Pattarozzi,
B. J. Duplantis,
Raymond B. Gary

Front row from left to right:
John P. Laborde,
D. Peter Canty,
James H. Stone,
Robert A. Bernhard,
Peter K. Barker,
David R. Voelker

not pictured:
David H. Welch

Board of Directors

James H. Stone
Stone Energy Corporation
Chairman

D. Peter Canty
Stone Energy Corporation
Former President and
Chief Executive Officer

Peter K. Barker [1, 3]
Goldman Sachs & Co.
Retired Partner

Robert A. Bernhard [1, 3]
Munn, Bernhard & Associates, Inc.
Co-Chairman

Lt. Gen. George R. Christmas (Ret.) [2, 3]
Marine Corps Heritage Foundation
President

B. J. Duplantis [3]
Gordon, Arata, McCollam,
Duplantis & Eagan
Senior Partner

Raymond B. Gary [1, 2, 3]
Morgan Stanley & Company, Inc.
Advisory Director

Joe R. Klutts—*Vice Chairman*
Klutts Exploration LLC
President

John P. Laborde
Tidewater Inc.
Retired Chairman Emeritus

Richard A. Pattarozzi [2, 3]
Shell Oil Company
Former Vice President

David R. Voelker [1, 2, 3]
Frantzen-Voelker Investments
Owner

David H. Welch
Stone Energy Corporation
President and
Chief Executive Officer

[1] Audit Committee Member
[2] Compensation Committee Member
[3] Nominating and Governance Committee Member

Senior Management

David H. Welch
President and Chief
Executive Officer

James H. Prince
Senior Vice President and
Chief Financial Officer

Craig L. Glassinger
Senior Vice President—Planning,
Acquisitions and Analysis

Andrew L. Gates III
Vice President, General Counsel
and Secretary

Eldon J. Louviere
Vice President—Land

Michael E. Madden
Vice President—Engineering

J. Kent Pierret
Vice President,
Chief Accounting Officer
and Treasurer

Gerald G. Yunker
Vice President—Resources

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-K

[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

Commission File Number: 1-12074

STONE ENERGY CORPORATION

(Exact Name of Registrant as Specified in Its Charter)

State of Incorporation: Delaware I.R.S. Employer Identification No. 72-1235413

625 E. Kaliste Saloom Road
Lafayette, Louisiana 70508
(Address of Principal Executive Offices) (Zip Code)

Registrant's Telephone Number, Including Area Code: (337) 237-0410

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

Title of each class	Name of each exchange on which registered
Common Stock, Par Value $.01 Per Share	New York Stock Exchange

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

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 the 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 Rule 12b-2 of the Act).

[x] Yes [ ] No

The aggregate market value of the voting stock held by non-affiliates of the registrant was approximately $978,130,217 as of June 30, 2003 (based on the last reported sale price of such stock on the New York Stock Exchange Composite Tape on that day).

As of March 1, 2004, the registrant had outstanding 26,480,434 shares of Common Stock, par value $.01 per share.

Document incorporated by reference: Portions of the Definitive Proxy Statement of Stone Energy Corporation relating to the Annual Meeting of Stockholders to be held on May 20, 2004 are incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

PART I

This section highlights information that is discussed in more detail in the remainder of the document. Throughout this document we make statements that are classified as "forward-looking." Please refer to the "Forward-Looking Statements" section beginning on page 8 of this document for an explanation of these types of statements. We use the terms "Stone", "Stone Energy", "company", "we", "us" and "our" to refer to Stone Energy Corporation. Certain terms relating to the oil and gas industry are defined in "Glossary of Certain Industry Terms", which begins on page G-1 of this Form 10-K.

ITEM 1. BUSINESS

The Company

Stone Energy is a Gulf Coast Basin-focused independent oil and gas company engaged in the acquisition and subsequent exploration, exploitation, development, production and operation of oil and gas properties. Our corporate headquarters are located at 625 E. Kaliste Saloom Road, Lafayette, Louisiana 70508.

Available Information

We make available free of charge on our Internet Web site (www.stoneenergy.com) our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and other filings pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, and amendments to such filings, as soon as reasonably practicable after each are electronically filed with, or furnished to, the Securities and Exchange Commission (the "SEC"). We also make available our Code of Business Conduct and Ethics, Corporate Governance Guidelines, and Audit, Compensation and Nominating and Governance Committee Charters, respectively, which have been approved by our board of directors, on our Internet Web site. We will make immediate disclosure either by Form 8-K or on our Web site of any change to, or waiver from, the Code of Business Conduct and Ethics for our principal executive and senior financial officers.

Strategy and Operational Overview

The Gulf of Mexico is a critical supply basin for the United States, traditionally accounting for approximately 25% of total U.S. oil and natural gas production. Properties located in the Gulf of Mexico are typically on 5,000-acre lease blocks and afford a substantial area to explore away from and beneath established production. We have established extensive geological, geophysical, technical and operational expertise in the Gulf Coast Basin. The application of these core strengths, combined with our detailed and thorough approach to evaluating mature fields and our utilization of new drilling, seismic and completion technologies, have enabled us to successfully exploit and derive significant value from mature Gulf Coast Basin properties. As of March 1, 2004, our property portfolio consisted of 60 active properties and 28 primary term leases in the Gulf Coast Basin and 33 active properties in the Rocky Mountains.

Our business strategy, which has remained consistent since 1993, is to increase reserves, production and cash flow through the acquisition, exploitation and development of mature properties located primarily in the Gulf Coast Basin. Since going public in 1993, we have grown reserves, production and cash flow from operating activities at compounded annual rates of 24%, 24% and 40%, respectively. Approximately 91% of our estimated proved reserves at December 31, 2003 and 94% of our production during 2003 were associated with our Gulf Coast Basin properties. As of December 31, 2003, we had estimated proved reserves of approximately 816.3 billion cubic feet of gas equivalent (Bcfe), 75% of which were classified as proved developed and 57% of which were natural gas. For the year ended December 31, 2003, we produced an average of 265.5 million cubic feet of gas equivalent (MMcfe) per day. As a result of successful drilling and strategic acquisitions, our estimated total proved reserves at December 31, 2003 were 9% higher than the prior year. During 2003, we generated net cash flow from operating activities of $391.5 million.

We apply the latest production techniques and geophysical interpretation tools to established fields with significant historical production that have been under-evaluated in recent years. We have grown our opportunity base through both the drillbit and strategic acquisitions, implementing a conservative financial strategy that incorporates a combination of operating cash flow, equity issuance and indebtedness to fund our acquisition and exploitation activities. While we have acquired substantially all of our properties from third parties, we have generated significant growth in reserves, production and prospect inventory subsequent to acquisition. We believe significant reserves remain to be discovered and exploited on properties that satisfy our acquisition criteria as the focus of oil and gas companies shifts over time. We also believe that we are well positioned to exploit these reserves by applying our technical expertise and our thorough, consistent and patient approach in the evaluation and acquisition of these properties.

We seek to acquire properties that have the following characteristics:

- primarily Gulf Coast Basin location;
- mature properties with an established production history and infrastructure;
- multiple productive sands and reservoirs;
- low production levels at acquisition with significant identified proven and potential reserves; and
- opportunity for us to obtain a controlling interest and serve as operator.

Our approach to evaluating mature fields in the Gulf Coast Basin involves a combination of techniques designed to generate opportunities and unlock value. By using the extensive production history and data accumulated on properties in the Gulf Coast Basin, our experienced technical teams construct an interpretation of the unique geology of each field to gain a better understanding of the potential location of previously untested or unexploited oil and gas accumulations. Using our interpretations, we are frequently able to combine development and exploratory targets in a single well to improve the chance of investment success. Since 1993, 75% of the wells we drilled were productive.

Prior to acquiring a property, we perform a thorough geological, geophysical and engineering analysis of the property to formulate a comprehensive development plan. To formulate this plan, we utilize the expertise of our technical team of 20 geologists, 19 geophysicists and 27 engineers. We also employ our extensive technical database, which includes both 3-D and 4-C seismic data. After we acquire a property, we seek to increase cash flow from existing reserves and establish additional proved reserves through the drilling of new wells, workovers and recompletions of existing wells and the application of other techniques designed to increase production.

Effective April 1, 2004, D. Peter Canty will retire as President and Chief Executive Officer. The Board of Directors has elected David H. Welch as President, Chief Executive Officer and a Director of Stone effective April 1, 2004.

Financial Overview

We were incorporated in Delaware in 1993. We completed our initial public offering of common stock in July 1993 and our shares are listed on the New York Stock Exchange under the ticker symbol "SGY." Additional offerings of common stock were completed in November 1996 and July 1999. We have maintained consistent and profitable growth since our initial public offering in 1993. We have generated net income in all calendar quarters except the fourth quarter of 1998 and third quarter of 2001, both of which included non-cash ceiling test write-downs of our oil and gas properties due to depressed oil and gas prices.

On September 30, 2003, we redeemed our outstanding $100 million aggregate principal amount of 8¾% Senior Subordinated Notes due 2007 at a call premium of 102.917%. The redemption was funded with available cash and borrowings under our bank credit facility. In December 2001, we issued $200 aggregate million principal amount of 8¼% Senior Subordinated Notes due 2011 to finance a portion of our acquisition of eight producing properties from Conoco, Inc.

We have a borrowing base under our bank credit facility of $350 million, with availability of an additional $157.9 million of borrowings as of March 1, 2004. The borrowing base limitation is re-determined periodically and is based on a borrowing base amount established by the bank group after its evaluation of the value of our estimated proved oil and gas reserves.

Oil and Gas Marketing

Our oil and natural gas production is sold at current market prices under short-term contracts providing for variable or market sensitive prices. We derived 12%, 13% and 10% of our total oil and natural gas revenue from Cinergy Marketing and Trading, Duke Energy Trading and Marketing LLC, and Equiva Trading Company, respectively, for the year ended December 31, 2003. No other purchaser accounted for 10% or more of our total oil and natural gas revenue during 2003. We believe that the loss of any of our major purchasers would not result in a material adverse effect on our ability to market future oil and gas production. From time to time, we may enter into transactions that hedge the price of oil and natural gas. See **"Item 7A. Quantitative and Qualitative Disclosures About Market Risk – Commodity Price Risk."**

Competition and Markets

Competition in the Gulf Coast Basin and the Rocky Mountains is intense, particularly with respect to the acquisition of producing properties and undeveloped acreage. We compete with major oil and gas companies and other independent producers of varying sizes, all of which are engaged in the acquisition of properties and the exploration and development of such properties. Many of our competitors have financial resources and exploration and development budgets that are substantially greater than ours, which may adversely affect our ability to compete. See **"Risk Factors – Competition within our industry may adversely affect our operations."**

The availability of a ready market for and the price of any hydrocarbons produced will depend on many factors beyond our control, including but not limited to the amount of domestic production and imports of foreign oil and liquefied natural gas, the marketing of competitive fuels, the proximity and capacity of natural gas pipelines, the availability of transportation and other market facilities, the demand for hydrocarbons, the effect of federal and state regulation of allowable rates of production, taxation and the conduct of drilling operations, and federal regulation of natural gas. In addition, the restructuring of the natural gas pipeline industry virtually eliminated the gas purchasing activity of traditional interstate gas transmission pipeline buyers. See **"Regulation - Federal Regulation of Sales and Transportation of Natural Gas."** Producers of natural gas have therefore been required to develop new markets among gas marketing companies, end users of natural gas and local distribution companies. All of these factors, together with economic factors in the marketing arena, generally may affect the supply of and/or demand for oil and natural gas and thus the prices available for sales of oil and natural gas.

Regulation

Our oil and natural gas operations are subject to numerous U.S. federal, state and local laws and regulations. See **"Risk Factors - Our oil and gas operations are subject to various U.S. federal, state and local government regulations that materially affect our operations."**

Regulation of Production. In all areas where we operate, there are statutory provisions regulating the production of oil and natural gas under which administrative agencies may enforce rules in connection with the location, spacing, drilling, operation and production of both oil and gas wells, determine the reasonable market demand for oil and gas and establish allowable rates of production. These regulatory orders can limit the number of wells or the location where wells may be drilled. Regulation can also restrict the rate of production below the rate that these wells would otherwise produce in the absence of such regulatory orders. Any of these actions could negatively impact the amount or timing of revenues.

Federal Leases. We have oil and gas leases both onshore and in the Gulf of Mexico, which were granted by the federal government. Operations on onshore federal leases must be conducted in accordance with permits issued by the federal Bureau of Land Management and are subject to a number of other regulatory restrictions, such as restrictions on activities that might interfere with wildlife breeding and nesting and drilling limitations imposed by resource management plans. Moreover, on certain federal leases, prior approval of drillsite locations must be obtained from the U.S. Environmental Protection Agency (the "EPA"). On large-scale projects, lessees may be required to perform Environmental Impact Statements to assess the environmental effects of potential development, which can delay project implementation or result in the imposition of environmental restrictions that could have a material impact on the cost or scope of such project.

Offshore leases are administered by the United States Department of the Interior Minerals Management Service (the "MMS"). Offshore lessees must obtain MMS approval of exploration, development and production plans prior to the commencement of these operations. In addition to permits required from other agencies (such as the U.S. Coast Guard, the Army Corps of Engineers and the EPA), lessees must obtain a permit from the MMS prior to the commencement of drilling. The MMS has enacted regulations requiring offshore production facilities located on the Outer Continental Shelf ("OCS") to meet stringent engineering, construction and safety specifications. The MMS also has regulations restricting the flaring or venting of natural gas, and prohibiting the flaring of liquid hydrocarbons and oil without prior authorization. Similarly, the MMS has enacted other regulations governing the plugging and abandoning of wells located offshore and the removal of all production facilities. Lessees must also comply with detailed MMS regulations governing the calculation of royalty payments and the valuation of production and permitted cost deductions for that purpose. In 2000, the MMS issued a final rule modifying the valuation procedures for the calculation of royalties owed for crude oil sales. When oil production sales are not in arms-length transactions, the royalties' calculation will be based on the valuation of oil production on spot market prices instead of the posted prices that were previously utilized. We are currently selling our crude oil under arms-length transactions in a manner that we believe to be acceptable to the MMS under its 2000 rule. This rule has not had a material adverse effect on our results of operations. On August 20, 2003, the MMS issued a proposed rule that would change certain components of its valuation procedures for the calculation of royalties owed for crude oil sales. The proposed changes include changing the valuation basis for transactions not at arm's-length from spot to New York Mercantile Exchange ("NYMEX") prices adjusted for locality and quality differentials, and clarifying the treatment of transactions under a joint operating agreement. Final comments on the proposed rule were due on November 10, 2003. We have no way of knowing whether the MMS will implement the proposed changes in a final rule or what effect such changes, if implemented, will have on our results of operations.

With respect to any operations conducted on offshore federal leases, liability may generally be imposed under the Outer Continental Shelf Lands Act (the "OCSLA") for costs of clean-up and damages caused by pollution resulting from these operations, other than damages caused by acts of war or the negligence of third parties. To cover the various obligations of lessees on the OCS, the MMS generally requires that lessees post substantial bonds or other acceptable financial assurances that these obligations will be met. The cost of bonds or other surety can be substantial and there is no assurance that bonds or other surety can be obtained in all cases.

Operators in the OCS waters of the Gulf of Mexico are also required to post area-wide bonds and individual lease bonds of $3 million and $1 million, respectively, unless the MMS allows exemptions or reduced amounts. We currently have an area-wide right-of-way bond for $0.3 million and an area-wide lessee's and operator's bond totaling $3 million issued in favor of the MMS for our existing offshore properties. The MMS also has discretionary authority to require supplemental bonding in addition to the foregoing required bonding amounts but this authority is only exercised on a case-by-case basis at the time of filing an assignment of record title interest for MMS approval. Based upon certain financial parameters, we have been granted exempt status by the MMS, which exempts us from the supplemental bonding requirements. There is no assurance, however, that such exemption will be maintained. Under certain circumstances, the MMS may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition and operations.

Oil Price Controls and Transportation Rates. Sales of crude oil, condensate and gas liquids are not currently regulated and are made at negotiated prices. Effective January 1, 1995, the Federal Energy Regulatory Commission (the "FERC") implemented regulations establishing an indexing system for transportation rates for oil that allowed oil pipelines to change rates yearly based on the change in an inflation index, the Producer Price Index for Finished Goods ("PPI-FG"), minus one percent. The implementation of these regulations did not have a material adverse effect on our results of operations. As required by its own regulations, in July 2000, the FERC reviewed its indexing methodology and concluded no change was needed. On judicial review, however, the Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") concluded that the FERC's decision was not adequately supported and remanded the decision to the FERC. In February 2003, on remand, the FERC changed the rate indexing methodology to the PPI-FG, but without the subtraction of one percent as had been done previously. The FERC made the change prospective only, but did allow oil pipelines to recalculate their maximum ceiling rates as though the new rate indexing methodology had been in effect since July 1, 2000.

Federal Regulation of Sales and Transportation of Natural Gas. Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938 (the "NGA"), the Natural Gas Policy Act of 1978 (the "NGPA") and regulations promulgated thereunder by the FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act (the "Decontrol Act"). The Decontrol Act removed all NGA and NGPA price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993.

Commencing in 1992, the FERC issued Order No. 636 and subsequent orders (collectively, "Order No. 636"), which require interstate pipelines to provide transportation separate, or "unbundled," from the pipelines' sales of gas. Also, Order No. 636 requires pipelines to provide open-access transportation on a basis that is equal for all shippers. Although Order No. 636 does not directly regulate our activities, the FERC has stated that it intends for Order No. 636 to foster increased competition within all phases of the natural gas industry. The implementation of these orders has not had a material adverse effect on our results of operations. The courts have largely affirmed the significant features of Order No. 636 and numerous related orders pertaining to the individual pipelines, although certain appeals remain pending and the FERC continues to review and modify its open access regulations.

In 2000, the FERC issued Order No. 637 and subsequent orders (collectively, "Order No. 637"), which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, pipeline penalties, rights of first refusal and information reporting. Most major aspects of Order No. 637 were upheld on judicial review, though certain issues, such as capacity segmentation and rights of first refusal, were remanded to the FERC, which issued a remand order in October of 2002. In January of 2004, the FERC denied rehearing of its October 2002 remand order. We cannot predict whether judicial review will be sought of the FERC's remand order and, if so, whether and to what extent the FERC's market reforms will survive such review and, if they do, 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 we will be affected by any action taken materially different than other natural gas producers and marketers with which we compete.

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 heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue.

Environmental Regulations. Our operations are subject to numerous stringent and complex 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 a permit before drilling commences, restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas and impose substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties, the issuance of remedial requirements, and the imposition of injunctive relief. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as the oil and gas industry in general. While we believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements would not have a material adverse impact on us, there is no assurance that this trend will continue in the future.

The Oil Pollution Act, as amended ("OPA"), and regulations implemented thereunder impose a variety of requirements on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in U.S. waters, including the OCS. A "responsible party" includes the owner or operator of an onshore facility, pipeline or vessel, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns liability to each responsible party for oil cleanup 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. Even if applicable, the liability limits for onshore facilities is $350 million while for offshore facilities it is the payment of all removal costs, plus up to $75 million in other damages. Few defenses exist to the liability imposed by OPA.

OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. Under OPA and a final rule adopted by the MMS in August 1998, responsible parties of covered offshore facilities that have a worst case oil spill of more than 1,000 barrels must demonstrate financial responsibility in amounts ranging from at least $10 million in specified state waters to at least $35 million in OCS waters, with higher amounts of up to $150 million in certain limited circumstances where the MMS believes such a level is justified by the risks posed by the operations, or if the worst case oil spill discharge volume possible at the facility may exceed the applicable threshold volume specified under the MMS's final rule. We do not anticipate that we will experience any difficulty in continuing to satisfy the MMS's requirements for demonstrating financial responsibility under OPA and the MMS's regulations.

The Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that transported or disposed or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

The Resource Conservation and Recovery Act, as amended ("RCRA"), generally does not regulate most wastes generated by the exploration and production of oil and natural gas. RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy." However, legislation has been proposed in Congress from time to time that would reclassify certain oil and gas exploration and production wastes as "hazardous wastes," which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If such legislation were to be enacted, it could have a significant impact on our operating costs, as well as the oil and gas industry in general. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

We currently own or lease, and have in the past owned or leased, onshore properties that for many years have been used for or associated with the exploration and production of oil and gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or under other locations where such wastes have been taken for disposal. In addition, most of these properties have been operated by third parties whose treatment and disposal or release of wastes is not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or closure operations to prevent future contamination.

The Federal Water Pollution Control Act, as amended ("FWPCA"), imposes restrictions and strict controls regarding the discharge of produced waters and other oil and gas waste into navigable waters. Permits must be obtained to discharge pollutants into waters and to conduct construction activities in waters and wetlands. The FWPCA and similar state laws provide for civil, criminal and administrative fines and penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. Many state discharge regulations and the Federal National Pollutant Discharge Elimination System general permits issued by the EPA prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the oil and gas industry into coastal waters. Although the costs to comply with zero discharge mandates under federal or state law may be significant, the entire industry is expected to experience similar costs and we believe that these costs will not have a material adverse impact on our results of operations or financial position. The EPA has adopted regulations requiring certain oil and gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans.

Employees

At March 1, 2004, we had 215 full time employees. We believe that our relationships with our employees are satisfactory. None of our employees are covered by a collective bargaining agreement. From time to time we utilize the services of independent contractors to perform various field and other services.

Forward-Looking Statements

The information in this Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical or present facts, that address activities, events, outcomes and other matters that we plan, expect, intend, assume, believe, budget, predict, forecast, project, estimate or anticipate (and other similar expressions) will, should or may occur in the future are forward-looking statements. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this Form 10-K.

Forward-looking statements appear in a number of places and include statements with respect to, among other things:

- any expected results or benefits associated with our acquisitions;
- estimates of our future oil and natural gas production, including estimates of any increases in oil and gas production;
- planned capital expenditures and the availability of capital resources to fund capital expenditures;
- our outlook on oil and gas prices;
- estimates of our oil and gas reserves;
- any estimates of future earnings growth;
- the impact of political and regulatory developments;
- our outlook on the resolution of pending litigation;
- our future financial condition or results of operations and our future revenues and expenses; and
- our business strategy and other plans and objectives for future operations.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and marketing of oil and natural gas. These risks include, but are not limited to, commodity price volatility, third party interruption of sales to market, inflation, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures and the other risks described in this Form 10-K.

Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data and the interpretation of that data by geological engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, these revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates are generally different from the quantities of oil and natural gas that are ultimately recovered.

Should one or more of the risks or uncertainties described above or elsewhere in this Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

Risk Factors

Our business is subject to a number of risks including, but not limited to, those described below:

Oil and gas price declines and volatility could adversely affect our revenues, cash flows and profitability.

Our revenues, profitability and future rate of growth depend substantially upon the market prices of oil and natural gas, which fluctuate widely. Factors that can cause this fluctuation include:

- relatively minor changes in the supply of and demand for oil and natural gas;
- market uncertainty;
- the level of consumer product demands;
- weather conditions;
- domestic and foreign governmental regulations;
- the price and availability of alternative fuels;
- political and economic conditions in oil producing countries, particularly those in the Middle East;
- the foreign supply of oil and natural gas;
- the price of oil and gas imports; and
- overall domestic and foreign economic conditions.

We cannot predict future oil and natural gas prices. At various times, excess domestic and imported supplies have depressed oil and gas prices. Declines in oil and natural gas prices may adversely affect our financial condition, liquidity and results of operations. Lower prices may reduce the amount of oil and natural gas that we can produce economically and may also create ceiling test write-downs of our oil and gas properties. Substantially all of our oil and natural gas sales are made in the spot market or pursuant to contracts based on spot market prices, not long-term fixed price contracts.

In an 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.

The marketability of our production depends mostly upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities.

The marketability of our production depends upon the availability, proximity, operation and capacity of 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. Federal and state regulation of oil and gas production and transportation, general economic conditions and changes in supply and demand could adversely affect our ability to produce and market our oil and natural gas. If market factors changed dramatically, the financial impact on us could be substantial. The availability of markets and the volatility of product prices are beyond our control and represent a significant risk.

We may not receive payment for a portion of our future production.

We may not receive payment for a portion of our future production. We have attempted to diversify our sales and obtain credit protections such as letters of credit, parental guarantees and prepayments from certain of our purchasers. We are unable to predict, however, what impact the financial difficulties of certain purchasers may have on our future results of operations and liquidity.

Estimates of oil and gas reserves are uncertain and inherently imprecise.

This Form 10-K contains estimates of our proved oil and gas reserves and the estimated future net cash flows from such reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and natural gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves set forth in this document and the information incorporated by reference. Our properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

At December 31, 2003, approximately 25% of our estimated proved reserves were proved undeveloped and 44% were proved developed non-producing. Proved undeveloped reserves and proved developed non-producing reserves, by their nature, are less certain than proved developed producing reserves. Estimation of these non-producing categories is nearly always based on volumetric calculations rather than the performance data used to estimate producing reserves. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Recovery of proved developed non-producing reserves requires capital expenditures to recomplete into the zones above producing intervals and is subject to the risk of a successful recompletion. Production revenues from proved non-producing reserves will not be realized until sometime in the future, sometimes not for many years. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of our oil and 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 estimated future net cash flow referred to in this Form 10-K is the current fair value of our estimated oil and gas reserves. In accordance with SEC requirements, the present value of estimated future net cash flows from proved reserves is 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 gas purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of oil and 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 SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor for Stone.

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

We use the full cost method of accounting for our oil and gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under full cost accounting rules, the net capitalized costs of oil and gas properties (net of related deferred taxes), including estimated capitalized abandonment costs, 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% and excluding cash flows related to estimated abandonment costs, plus the lower of cost or fair value of unproved properties. If net capitalized costs of oil and 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 net income. The risk that we will be required to write down the carrying value of oil and gas properties increases when oil and natural gas prices are low or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves. We recorded an after-tax write-down of $154.5 million ($237.7 million pre-tax) at the end of the third quarter of 2001 due to low natural gas prices on the last day of that quarter. There was no loss of proved reserve volumes associated with the ceiling test write-down. We cannot assure you that we will not experience ceiling test write-downs in the future.

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

We have historically addressed our short and long-term liquidity needs through the use of bank credit facilities, the issuance of debt and equity securities and the use of cash flow provided by operating activities. We continue to examine the following alternative sources of capital:

- bank borrowings or the issuance of debt securities;
- the issuance 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 fully 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 acquisition, exploration, exploitation, development and production of oil and gas reserves. Our capital expenditures, including acquisitions and exclusive of estimated asset retirement costs, were $362.6 million during 2003, $215.6 million during 2002 and $641.3 million during 2001. We have budgeted total capital expenditures in 2004, excluding property acquisitions and capitalized salaries, general and administrative costs and interest, of approximately $280 million. If low oil and natural gas prices, operating difficulties or other factors, many of which are beyond our control, cause our revenues and cash flows from operating activities to decrease, we may be limited in our ability to spend the capital necessary to complete our capital expenditures program. In addition, if our borrowing base under our credit facility is re-determined to a lower amount, this could adversely affect our ability to fund our planned capital expenditures. After utilizing our available sources of financing, we may be forced to raise additional debt or equity proceeds to fund such capital expenditures. We cannot assure you that additional debt or equity financing will be available or cash flows provided by operations will be sufficient to meet these requirements.

We may not be able to replace production with new reserves.

In general, the volume of production from oil and gas properties declines as reserves are depleted. The decline rates depend on reservoir characteristics. During 2003, 94% of our production and 91% of our estimated proved reserves were derived from Gulf of Mexico reservoirs, while the remaining portions of our production and reserves were derived from the Rocky Mountain region. Gulf of Mexico reservoirs tend to be recovered quickly through production with associated steep declines, while declines in other regions after initial flush production tend to be relatively low. Our reserves will decline as they are produced unless we acquire properties with proved reserves or conduct successful development and exploration drilling activities. Our future natural gas and oil production is highly dependent upon our level of success in finding or acquiring additional reserves.

Our recent growth is due in large part to acquisitions of producing properties. The successful acquisition of producing properties requires an assessment of a number of factors, some of which are beyond our control. These factors include recoverable reserves, future oil and gas prices, operating costs, and potential environmental and other liabilities, title issues and other factors. Such assessments are inexact and their accuracy is inherently uncertain. In connection with such assessments, we perform a review of the subject properties, which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, the review will not permit a buyer to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We cannot assure you that we will be able to acquire properties at acceptable prices because the competition for producing oil and gas properties is intense and many of our competitors have financial and other resources that are substantially greater than those available to us.

Our strategy includes increasing our reserves, production and cash flow by the implementation of a carefully designed field-wide development plan. These development plans are formulated both prior to and after the acquisition of a property. However, we cannot assure you that our future development and exploration activities on the properties we acquire will result in additional proved reserves or that we will be able to drill productive wells at acceptable costs.

There are uncertainties in successfully integrating our acquisitions.

Integrating acquired businesses and properties involves a number of special risks. These risks include the possibility that management may be distracted from regular business concerns by the need to integrate operations and that unforeseen difficulties can arise in integrating operations and systems and in retaining and assimilating employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results.

Our operations are subject to numerous risks of oil and gas drilling and production activities.

Oil and gas drilling and production activities are subject to numerous risks, including the risk that no commercially productive oil or natural gas reservoirs will be found. The cost of drilling and completing wells is often uncertain. Oil and gas drilling and production activities may be shortened, delayed or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- weather conditions;
- shortages in experienced labor; and
- shortages or delays in the delivery of equipment.

The prevailing prices of oil and natural gas also affect the cost of and the demand for drilling rigs, production equipment and related services.

We cannot assure you that the new wells we drill will be productive or that we will recover all or any portion of our investment. Drilling for oil and natural gas may be unprofitable. Drilling activities can result in dry wells and wells that are productive but do not produce sufficient net revenue after operating and other costs to recoup drilling costs.

Our industry experiences numerous operating risks.

The exploration, development and operation of oil and gas properties involves a variety of operating risks including the risk of fire, explosions, blowouts, pipe failure, abnormally pressured formations and environmental hazards. Environmental hazards include oil spills, gas leaks, pipeline ruptures or discharges of toxic gases. If any of these industry-operating risks occur, we could have substantial losses. Substantial losses may be caused by injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. Additionally, our offshore operations are subject to the additional hazards of marine operations, such as capsizing, collision and adverse weather and sea conditions. In accordance with industry practice, we maintain insurance against some, but not all, of the risks described above.

We have begun to explore for natural gas and oil in the deep waters of the Gulf of Mexico (water depths greater than 2,000 feet) where operations are more difficult than in shallower waters. Our deepwater drilling and operations require the application of recently developed technologies that involve a higher risk of mechanical failure. The deep waters of the Gulf of Mexico often lack the physical and oilfield service infrastructure present in the shallower waters. As a result, deepwater operations may require a significant amount of time between a discovery and the time that we can market the natural gas or oil, increasing the risks involved with these operations.

During 2002, we experienced two separate production interruptions resulting from two named storms in the Gulf of Mexico. At the time, we maintained loss of production insurance to protect us against uncontrollable disruptions in production operations from events of this nature. However, we decided not to renew loss of production coverage effective May 1, 2003, based on our assessment of the cost to retain this policy as compared to the benefits we received as a result of production interruptions caused by these storms.

We maintain insurance of various types to cover our operations, including maritime employer's liability and comprehensive general liability. Coverage amounts are provided by primary and excess umbrella liability policies with ultimate limits of $100 million. In addition, we maintain up to $100 million in operator's extra expense insurance, which provides coverage for the care, custody and control of wells drilled and/or completed plus re-drill and pollution coverage. The exact amount of coverage for each well is dependent upon its depth and location.

We cannot assure you that our insurance will be adequate to cover losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase. No assurance can be given that we will be able to maintain insurance in the future at rates we consider reasonable. The occurrence of a significant event, not fully insured or indemnified against, could have a material adverse affect on our financial condition and operations.

Terrorist attacks aimed at our facilities could adversely affect our business.

The U.S. government has issued warnings that U.S. energy assets may be the future targets of terrorist organizations. These developments have subjected our operations to increased risks. Any future terrorist attack at our facilities, or those of our purchasers, could have a material adverse affect on our financial condition and operations.

A majority of our production, revenue and cash flow from operating activities are derived from assets that are concentrated in a geographic area.

Approximately 91% of our estimated proved reserves at December 31, 2003 and 94% of our production during 2003 were associated with our Gulf Coast Basin properties. Accordingly, if the level of production from these properties substantially declines, it could have a material adverse effect on our overall production level and our revenue.

Our debt level and the covenants in the agreements governing our debt could negatively impact our financial condition, results of operations and business prospects.

As of December 31, 2003, we had $370.0 million in outstanding indebtedness. We have a borrowing base under our bank credit facility of $350 million with availability of an additional $157.9 million of borrowings as of March 1, 2004.

The terms of the agreements governing our debt impose significant restrictions on our ability to take a number of actions that we may otherwise desire to take, including:

- incurring additional debt;
- paying dividends on stock, redeeming stock or redeeming subordinated debt;
- making investments;
- creating liens on our assets;
- selling assets;
- guaranteeing other indebtedness;
- entering into agreements that restrict dividends from our subsidiary to us;
- merging, consolidating or transferring all or substantially all of our assets; and
- entering into transactions with affiliates.

Our level of indebtedness, and the covenants contained in the agreements governing our debt, could have important consequences on our operations, including:

- making it more difficult for us to satisfy our obligations under the indentures or other debt and increasing the risk that we may default on our debt obligations;
- requiring us to dedicate a substantial portion of our cash flow from operating activities to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and other general business activities;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- detracting from our ability to successfully withstand a downturn in our business or the economy generally;
- placing us at a competitive disadvantage against other less leveraged competitors; and
- making us vulnerable to increases in interest rates, because debt under our credit facility will be at variable rates.

We may be required to repay all or a portion of our debt on an accelerated basis in certain circumstances. If we fail to comply with the covenants and other restrictions in the agreements governing our debt, it could lead to an event of default and the acceleration of our repayment of outstanding debt. Our ability to comply with these covenants and other restrictions may be affected by events beyond our control, including prevailing economic and financial conditions. Our borrowing base under the credit facility, which is re-determined periodically, is based on an amount established by the bank group after its evaluation of our proved oil and gas reserve values. Upon a re-determination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to repay a portion of our bank debt.

We may not have sufficient funds to make such repayments. If we are unable to repay our debt out of cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. We cannot assure you that we will be able to generate sufficient cash flow from operating activities to pay the interest on our debt or that future borrowings, equity financings or proceeds from the sale of assets will be available to pay or refinance such debt. The terms of our debt, including our credit facility and our indentures, may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets 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, refinancing or sale of assets can be successfully completed.

Competition within our industry may adversely affect our operations.

Competition in the Gulf Coast Basin and the Rocky Mountains is intense, particularly with respect to the acquisition of producing properties and undeveloped acreage. We compete with major oil and gas companies and other independent producers of varying sizes, all of which are engaged in the acquisition of properties and the exploration and development of such properties. Many of our competitors have financial resources and exploration and development budgets that are substantially greater than ours, which may adversely affect our ability to compete.

Our oil and gas operations are subject to various U.S. federal, state and local governmental regulations that materially affect our operations.

Our oil and gas operations are subject to various U.S. federal, state and local laws and regulations. These laws and regulations may be changed in response to economic or political conditions. Regulated matters include: permits for exploration, development and production operations; limitations on our drilling activities in environmentally sensitive areas, such as wetlands and restrictions on the way we can release materials in the environment; bonds or other financial responsibility requirements to cover drilling contingencies and well plugging and abandonment costs; reports concerning operations, the spacing of wells and unitization and pooling of properties; and taxation. At various times, regulatory agencies have imposed price controls and limitations on oil and gas production. In order to conserve supplies of oil and gas, these agencies have restricted the rates of flow of oil and gas wells below actual production capacity. In addition, the OPA requires operators of offshore facilities such as us to prove that they have the financial capability to respond to costs that may be incurred in connection with potential oil spills. Under OPA and other federal and state environmental statutes, the CERCLA and the RCRA, owners and operators of certain defined onshore and offshore facilities are strictly liable for spills of oil and other regulated substances, subject to certain limitations. Consequently, a substantial spill from one of our facilities subject to laws such as OPA, CERCLA and RCRA could require the expenditure of additional, and potentially significant, amounts of capital, or could have a material adverse effect on our earnings, results of operations, competitive position or financial condition. Federal, state and local laws regulate production, handling, storage, transportation and disposal of oil and gas, by-products from oil and gas and other substances, and materials produced or used in connection with oil and gas operations. We cannot predict the ultimate cost of compliance with these requirements or their impact on our earnings, operations or competitive position.

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 individuals will remain with us for the immediate or foreseeable future. We do not have employment contracts with any of these individuals. The unexpected loss of the services of one or more of these individuals could have an adverse effect on us.

Hedging transactions may limit our potential gains.

In order to manage our exposure to price risks in the marketing of our oil and natural gas, we periodically enter into oil and gas price hedging arrangements with respect to a portion of our expected production. Our hedging policy provides that, without prior approval of our board of directors, generally not more than 50% of our estimated production quantities may be hedged. These arrangements may include futures contracts on the NYMEX. While intended to reduce the effects of volatile oil and gas prices, such transactions, depending on the hedging instrument used, may limit our potential gains if oil and gas prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparties to our futures contracts fail to perform the contracts; or
- a sudden, unexpected event materially impacts oil or natural gas prices.

Ownership of working interests, net profits interests and overriding royalty interests in certain of our properties by certain of our officers and directors may create conflicts of interest.

James H. Stone and Joe R. Klutts, both directors of Stone, collectively own 9% of the working interest in certain wells drilled on Section 19 on the east flank of the Weeks Island Field. These interests were acquired at the same time that our predecessor company acquired its interests in the Weeks Island Field. In their capacity as working interest owners, they are required to pay their proportional share of all costs and are entitled to receive their proportional share of revenue.

D. Peter Canty, Stone's Chief Executive Officer, and James H. Prince, Stone's Chief Financial Officer, were granted net profit interests in some of Stone's oil and gas properties acquired prior to our initial public offering in 1993. In addition, Michael E. Madden, Stone's Vice President of Engineering, was granted an overriding royalty interest in some of Stone's properties by an independent third party. At the time he was granted this interest, Mr. Madden was serving Stone as an independent engineering consultant. The recipients of net profits and overriding royalty interests are not required to pay capital costs incurred on the properties burdened by such interests.

As a result of these transactions, a conflict of interest may exist between us and such directors and officers with respect to the drilling of additional wells or other development operations.

We do not pay dividends.

We have never declared or paid any cash dividends on our common stock and have no intention to do so in the near future. The restrictions on our present or future ability to pay dividends are included in the provisions of the Delaware General Corporation Law and in certain restrictive provisions in the indenture executed in connection with our 8¼% Senior Subordinated Notes due 2011. In addition, we have entered into a credit facility that contains provisions that may have the effect of limiting or prohibiting the payment of dividends.

Our Certificate of Incorporation and Bylaws have provisions that discourage corporate takeovers and could prevent stockholders from realizing a premium on their investment.

Certain provisions of our Certificate of Incorporation, Bylaws and shareholders' rights plan and the provisions of the Delaware General Corporation Law may encourage persons considering unsolicited tender offers or other unilateral takeover proposals to negotiate with our board of directors rather than pursue non-negotiated takeover attempts. Our Bylaws provide for a classified board of directors. Also, our Certificate of Incorporation authorizes our board of directors to issue preferred stock without stockholder approval and to set the rights, preferences and other designations, including voting rights of those shares, as the board may determine. Additional provisions include restrictions on business combinations and the availability of authorized but unissued common stock. These provisions, alone or in combination with each other and with the rights plan described below, may discourage transactions involving actual or potential changes of control, including transactions that otherwise could involve payment of a premium over prevailing market prices to stockholders for their common stock.

During 1998, our board of directors adopted a shareholder rights agreement, pursuant to which uncertificated 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 October 26, 1998. 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.

ITEM 2. PROPERTIES

We have grown principally through the acquisition and subsequent development and exploitation of properties purchased from major and independent oil and gas companies. As of March 1, 2004, our property portfolio consisted of 60 active properties and 28 primary term leases in the Gulf Coast Basin and 33 active properties in the Rocky Mountains.

As of January 1, 2004, we served as operator on 59% of our active properties, including a 67% operating percentage on our Gulf Coast Basin properties. The properties that we operate accounted for 78% of our year-end 2003 estimated proved reserves. This high operating percentage allows us to better control the timing, selection and costs of our drilling and production activities.

Oil and Natural Gas Reserves

The information in this annual report on Form 10-K relating to Stone's estimated oil and gas reserves and the estimated future net cash flows attributable thereto is based upon the reserve reports (the "Reserve Reports") prepared as of December 31, 2003 by Atwater Consultants, Ltd., Ryder Scott Company, L.P., and Cawley, Gillespie & Associates, Inc., all independent petroleum engineers. These independent petroleum engineers reviewed 100% of our total proved reserves as of December 31, 2003. All product pricing and cost estimates used in the Reserve Reports are in accordance with the rules and regulations of the SEC, and, except as otherwise indicated, the reported amounts give no effect to federal or state income taxes otherwise attributable to estimated future cash flow from the sale of oil and natural gas. The present value of estimated future net cash flows has been calculated using a discount factor of 10%.

You should not assume that the estimated future net cash flows or the present value of estimated future net cash flows, referred to in the table below, represent the fair value of our estimated oil and gas reserves. As required by the SEC, we determine estimated future net cash flows using period-end market prices for oil and gas without considering hedge contracts in place at the end of the period. Using the information contained in the Reserve Reports, the average 2003 year-end product prices for all of our properties were $31.79 per barrel of oil and $6.30 per Mcf of gas. The following table sets forth our estimated net proved oil and natural gas reserves and the present value of estimated future net cash flows before income taxes related to such reserves as of December 31, 2003.

	Proved Developed	Proved Undeveloped	Total Proved	Percent Proved Developed
Oil (MBls)...	45,128	14,034	59,162	76%
Natural gas (MMcf).......................................	339,664	121,659	461,323	74%
Total oil and natural gas (MMcfe).......................	610,432	205,863	816,295	75%
Estimated future net cash flows before income taxes (in thousands)..	$2,725,342	$907,966	$3,633,308	75%
Present value of estimated future net cash flows before income taxes (in thousands)..................	$1,853,478	$526,781	$2,380,259	78%

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and the timing of development expenditures, including many factors beyond the control of the producer. The reserve data set forth herein only represents estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment and the existence of development plans. Results of drilling, testing and production subsequent to the date of an estimate may justify a revision of such estimates. Accordingly, reserve estimates are generally different from the quantities of oil and gas that are ultimately produced. Further, the estimated future net revenues from proved reserves and the present value thereof are based upon certain assumptions, including geological success, prices, future production levels and costs that may not prove to be correct. Predictions about prices and future production levels are subject to great uncertainty, and the meaningfulness of these estimates depends on the accuracy of the assumptions upon which they are based.

As an operator of domestic oil and gas properties, we have filed Department of Energy Form EIA-23, "Annual Survey of Oil and Gas Reserves," as required by Public Law 93-275. There are differences between the reserves as reported on Form EIA-23 and as reported herein. The differences are attributable to the fact that Form EIA-23 requires that an operator report the total reserves attributable to wells that it operates, without regard to percentage ownership (*i.e.*, reserves are reported on a gross operated basis, rather than on a net interest basis) or non-operated wells in which it owns an interest.

Acquisition, Production and Drilling Activity

Acquisition and Development Costs. The following table sets forth certain information regarding the costs incurred in our acquisition, development and exploratory activities during the periods indicated.

	Year Ended December 31,		
	2003	2002	2001
		(In thousands)	
Acquisition costs, net of sales of unevaluated properties..	$54,456	$14,071	$328,778
Development costs	109,507	96,426	119,426
Exploratory costs..	175,864	86,063	176,679
Subtotal..	339,827	196,560	624,883
Capitalized general and administrative costs and interest, net of fees and reimbursements	22,755	19,039	16,394
Asset retirement costs (1)................................	49,728	-	-
Total additions to oil and gas properties..................	$412,310	$215,599	$641,277

(1) Recorded in connection with the application of Statement of Financial Accounting Standards No. 143.

Productive Well and Acreage Data. The following table sets forth certain statistics regarding the number of productive wells and developed and undeveloped acreage as of December 31, 2003.

	Gross	Net
Productive Wells:		
Oil (1):		
Gulf Coast Basin	191.00	104.44
Rocky Mountain Basin	166.00	106.03
	357.00	210.47
Gas (2):		
Gulf Coast Basin	174.00	119.66
Rocky Mountain Basin	59.00	26.95
	233.00	146.61
Total	590.00	357.08
Developed Acres:		
Gulf Coast Basin	41,740.12	26,684.64
Rocky Mountain Basin	42,021.81	20,579.14
Total	83,761.93	47,263.78
Undeveloped Acres (3):		
Gulf Coast Basin	452,913.00	314,896.68
Rocky Mountain Basin	219,432.49	151,062.73
Total	672,345.49	465,959.41

(1) 15 gross wells each have dual completions.
(2) 5 gross wells each have dual completions.
(3) Leases covering approximately 5% of our undeveloped gross acreage will expire in 2004, 5% in 2005, 2% in 2006, 1% in 2007 and 4% in 2008. Leases covering the remainder of our undeveloped gross acreage (83%) are held by production.

Drilling Activity. The following table sets forth our drilling activity for the periods indicated.

	Year Ended December 31,					
	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive	24.00	20.81	15.00	10.59	22.00	13.84
Nonproductive	7.00	4.50	7.00	5.35	20.00	15.81
Development Wells:						
Productive	20.00	13.64	22.00	10.64	20.00	12.03
Nonproductive	1.00	0.85	4.00	2.66	1.00	0.51

Title to Properties

We believe that we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the oil and gas industry. Our properties are subject to customary royalty interests, liens for current taxes and other burdens, which we believe do not materially interfere with the use of or affect the value of such properties. Prior to acquiring undeveloped properties, we perform a title investigation that is thorough but less vigorous than that conducted prior to drilling, which is consistent with standard practice in the oil and gas industry. Before we commence drilling operations, we conduct a thorough title examination and perform curative work with respect to significant defects before proceeding with operations. We have performed a thorough title examination with respect to substantially all of our active properties.

ITEM 3. LEGAL PROCEEDINGS

Goodrich Petroleum Corporation, Goodrich Petroleum Company, L.L.C. and Goodrich Petroleum Company-Lafitte, L.L.C. filed civil action number 2000-06437, in Harris County, Texas, against Stone Energy Corporation, seeking seismic data at Lafitte Field and unspecified damages. On October 29, 2003, after a trial of this matter, the jury awarded Goodrich Petroleum Company-Lafitte, L.L.C. damages in the amount of approximately $0.5 million. As of March 1, 2004, the court had not entered a judgement in this case. There has been no indication whether the plaintiff will appeal this decision. We are evaluating whether an appeal will be filed by Stone.

We are named as a defendant in certain lawsuits and are a party to certain regulatory proceedings arising in the ordinary course of business. We do not expect these matters, individually or in the aggregate, to have a material adverse effect on our financial condition.

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

No matters were submitted for a vote of our stockholders during the fourth quarter of 2003.

ITEM 4A. EXECUTIVE OFFICERS OF THE REGISTRANT

We announced that effective April 1, 2004, D. Peter Canty will retire as President and Chief Executive Officer. Mr. Canty will continue to serve as one of our directors. Effective April 1, 2004, Mr. David H. Welch will become President, Chief Executive Officer and a director of Stone. Mr. Welch most recently served as Senior Vice President of BP America, Inc.

The following table sets forth information regarding the names, ages (as of March 1, 2004) and positions held by each of our executive officers, followed by biographies describing the business experience of our executive officers for at least the past five years. Our executive officers serve at the discretion of the board of directors.

Name	Age	Position
D. Peter Canty	57	President, Chief Executive Officer and Director
Andrew L. Gates, III	56	Vice President, General Counsel and Secretary
Craig L. Glassinger	56	Senior Vice President – Planning, Acquisitions and Analysis
E. J. Louviere	55	Vice President – Land
Michael E. Madden	58	Vice President – Engineering
J. Kent Pierret	48	Vice President, Chief Accounting Officer and Treasurer
James H. Prince	61	Senior Vice President and Chief Financial Officer
Gerald G. Yunker	47	Vice President – Resources

D. Peter Canty was named Chief Executive Officer on January 1, 2001 and President in March 1994. He has also served as a Director since March 1993. Mr. Canty will resign as President and Chief Executive Officer effective April 1, 2004. He has been employed by Stone Energy since its inception in 1993.

Andrew L. Gates, III has served as Vice President, General Counsel and Secretary since August 1995.

Craig L. Glassinger was named Senior Vice President – Planning, Acquisitions and Analysis in April 2002. From December 1995 to February 2001 he served as Vice President – Acquisitions and from February 2001 until April 2002 as Vice President – Resources.

E. J. Louviere has served as Vice President – Land since June 1995. He has been employed by Stone since its inception in 1993.

Michael E. Madden was named Vice President – Engineering in March 2002. Previously, he served as the Lafayette District Manager from February 2001 to March 2002. He has been employed by Stone Energy since its inception in 1993 as a reservoir engineer.

J. Kent Pierret was named Vice President and Chief Accounting Officer in June 1999. Mr. Pierret was named Treasurer in February 2004. Prior to June 1999, he was a partner in the firm of Pierret, Veazey & Co., CPAs (and its predecessors) from May 1988 to May 1999, which performed a substantial amount of our financial reporting, tax compliance and financial advisory services.

James H. Prince was named Chief Financial Officer in August 1999. He previously served as Chief Accounting Officer and Controller from 1993 to June 1999 and Treasurer from June 1999 to February 2004. In April 2002, he became a Senior Vice President. He has been employed by Stone Energy since its inception in 1993.

Gerald G. Yunker was named Vice President – Resources in March 2002. Previously, he served Stone Energy in various capacities as a geologist, a Development Manager, and the Planning, Acquisition & Analysis Manager from October 1994 to March 2002.

PART II

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

Since July 9, 1993, our common stock has been listed on the New York Stock Exchange under the symbol "SGY." The following table sets forth, for the periods indicated, the high and low sales prices per share of our common stock.

	High	Low
2002		
First Quarter	$39.24	$32.15
Second Quarter	43.90	36.40
Third Quarter	40.44	29.15
Fourth Quarter	34.92	28.65
2003		
First Quarter	$36.20	$30.75
Second Quarter	44.68	33.42
Third Quarter	42.08	34.40
Fourth Quarter	43.00	34.54
2004		
First Quarter (through March 1, 2004)	$46.42	$40.55

On March 1, 2004, the last reported sales price on the New York Stock Exchange Composite Tape was $46.38 per share. As of that date, there were 203 holders of record of our common stock.

Dividend Restrictions

In the past, we have not paid cash dividends on our common stock, and we do not intend to pay cash dividends on our common stock in the foreseeable future. We currently intend to retain earnings, if any, for the future operation and development of our business. The restrictions on our present or future ability to pay dividends are included in the provisions of the Delaware General Corporation Law and in certain restrictive provisions in the indenture executed in connection with our 8¼% Senior Subordinated Notes due 2011. In addition, we have entered into a credit facility that contains provisions that may have the effect of limiting or prohibiting the payment of dividends.

Equity Compensation Plan Information

Please refer to Item 12 of this Annual Report on Form 10-K for information concerning securities authorized under our equity compensation plan.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth a summary of selected historical financial information for each of the years in the five-year period ended December 31, 2003. This information is derived from our Financial Statements and the notes thereto. See **"Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations"** and **"Item 8. Financial Statements and Supplementary Data."**

	Year Ended December 31,				
	2003	2002	2001	2000	1999
	(In thousands, except per share amounts)				
***Statement of Operations Data*:**					
Operating revenue:					
Oil production	$174,139	$155,913	$103,053	$118,628	$70,025
Gas production	334,166	221,582	292,446	263,310	148,390
Total operating revenue	508,305	377,495	395,499	381,938	218,415
Operating expenses:					
Normal lease operating expenses	61,382	60,952	47,564	41,474	33,372
Major maintenance expenses	11,404	15,721	6,508	6,538	1,115
Production taxes	5,975	5,039	6,408	7,607	2,933
Depreciation, depletion and amortization	170,845	160,762	158,893	110,859	101,105
Accretion expense	6,292	-	-	-	-
Write-down of oil and gas properties	-	-	237,741	-	-
Derivative expense	8,711	15,968	2,604	-	-
Bad debt expense (1)	-	-	2,343	-	-
Salaries, general and administrative expenses	14,870	13,190	13,004	12,725	10,764
Incentive compensation expense	2,636	851	523	1,722	1,510
Total operating expenses	282,115	272,483	475,588	180,925	150,799
Income (loss) from operations	226,190	105,012	(80,089)	201,013	67,616
Other (income) expenses:					
Interest expense	19,132	23,111	4,895	9,395	15,186
Other expense	538	-	-	-	-
Early extinguishment of debt	4,661	-	-	-	-
Merger expenses	-	-	25,785	1,297	-
Other income	(3,133)	(3,328)	(2,997)	(4,228)	(2,349)
Total other expenses	21,198	19,783	27,683	6,464	12,837
Income (loss) before income taxes	204,992	85,229	(107,772)	194,549	54,779
Income tax provision (benefit)	71,747	29,830	(36,397)	68,092	17,713
Income (loss) before cumulative effects of accounting changes, net of tax	133,245	55,399	(71,375)	126,457	37,066
Cumulative effects of accounting changes, net of tax (2)	1,225	-	-	-	-
Net income (loss)	$134,470	$55,399	($71,375)	$126,457	$37,066
Earnings and dividends per common share:					
Income (loss) before cumulative effects of accounting changes per share	$5.05	$2.10	($2.73)	$4.90	$1.61
Earnings (loss) per common share	$5.10	$2.10	($2.73)	$4.90	$1.61
Income (loss) before cumulative effects of accounting changes per share assuming dilution	$5.02	$2.09	($2.73)	$4.80	$1.58
Earnings (loss) per common share assuming dilution	$5.07	$2.09	($2.73)	$4.80	$1.58
Cash dividends declared	-	-	-	-	-
Cash Flow Data:					
Net cash provided by operating activities	$391,539	$222,921	$315,617	$302,082	$123,010
Net cash used in investing activities	(341,908)	(216,600)	(656,847)	(258,637)	(158,567)
Net cash provided by (used in) financing activities	(60,140)	8,133	275,828	17,461	42,327
Balance Sheet Data (at end of period):					
Working capital (deficit)	($38,474)	($1,213)	($18,097)	$53,065	$12,509
Oil and gas properties, net	1,317,933	1,047,936	993,906	747,574	587,661
Total assets	1,434,277	1,179,371	1,101,783	944,104	706,958
Long-term debt, less current portion	370,000	431,000	426,000	148,000	134,000
Stockholders' equity	710,277	577,488	530,025	587,577	452,870

(1) Relates to 100% allowance for production receivable due from Enron North America.

(2) Cumulative effects of accounting changes related to the adoption of SFAS No. 143 and change to the Units of Production method of DD&A.

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

The following discussion is intended to assist in understanding our financial position and results of operations for each of the years in the three-year period ended December 31, 2003. Our Financial Statements and the notes thereto, which are found elsewhere in this Form 10-K contain detailed information that should be referred to in conjunction with the following discussion. See **"Item 8. – Financial Statements and Supplementary Data."**

Executive Overview

We are an independent oil and gas company engaged in the acquisition, exploration, exploitation, development and operation of oil and gas properties onshore and in the Gulf of Mexico and in several basins in the Rocky Mountains. Our business strategy, which has remained consistent since 1993, is to increase reserves, production and cash flow through the acquisition, exploitation and development of mature properties located primarily in the Gulf Coast Basin. Our revenue, profitability and future rate of growth are dependent upon the prices of oil and natural gas. Over the last few years, the prices of oil and gas have been highly volatile. The increased volatility is attributable to a variety of factors impacting supply and demand, including weather conditions, political events and economic events we can neither control nor predict.

Effective April 1, 2004, D. Peter Canty will retire as President and Chief Executive Officer. The Board of Directors has elected David H. Welch as President, Chief Executive Officer and a Director of Stone effective April 1, 2004.

Over the last several years, we have financed our drilling budget primarily with cash flow from operating activities. We accessed the capital markets and issued debt securities to finance the $300 million property acquisition from Conoco, Inc. on December 31, 2001.

2003 Highlights.

Our primary 2003 goals were to grow production and reserves and lower debt levels. Although total production volumes during 2003 did not exceed volumes produced during 2002, we did achieve other goals indicated below:

- *Record Reserve Additions from Drilling* – At December 31, 2003, our estimated total proved reserves were 816.3 Bcfe, which represents a 9% growth over prior year estimates and a 167% replacement of 2003 production volumes, 143% of which was achieved through drilling.

- *Drilling Success* – During 2003, of the 52 wells we drilled 44 were productive, 85% rate of success.

- *Record Level of Revenue* – Oil and gas revenue totaled $508.3 million, or 35% higher than 2002 revenue of $377.5 million.

- *Reduced Long-Term Debt* -- During 2003, we had net repayments of long-term debt of $61 million through the redemption of our 8¾% Senior Subordinated Notes and repayments on our bank credit facility. As a result of these repayments and a 143% increase in net income for 2003, our debt-to-book capital ratio at December 31, 2003 improved to 34% versus 43% on December 31, 2002.

- *MMS SAFE Award Finalist* – Stone has been recognized by the MMS as one of five 2003 SAFE Award Finalists for "High Activity Operators."

2004 Outlook.

Based on our outlook of commodity prices and our estimated production, we expect to finance our 2004 capital program with cash flow from operating activities. We have hedged a portion of our estimated 2004 Gulf Coast Basin production at prices of $3.50 per MMBtu of natural gas and $25.00 per barrel of oil. In addition, we have swap contracts for a portion of our estimated production from the Rocky Mountains at a price of $3.42 per MMBtu of natural gas.

Our 2004 capital expenditures budget is approximately $280 million, excluding acquisitions and capitalized interest and general and administrative expenses. To the extent that 2004 cash flow from operating activities exceeds our estimated 2004 capital expenditures, we plan to pay down a portion of our existing debt. If cash flow from operating activities during 2004 is not sufficient to fund estimated 2004 capital expenditures, we believe that our bank credit facility, under which we have $157.9 million of available borrowings at March 1, 2004, will provide us with adequate liquidity.

We have begun to explore for natural gas and oil in the deep waters of the Gulf of Mexico (water depths greater than 2,000 feet) where operations are more difficult than in shallower waters. A team of experienced technical personnel has been established to evaluate potential prospects and opportunities with other operators. We have identified one prospect that we expect to drill during 2004 in the deep water.

Results of Operation

The following table sets forth certain operating information with respect to our oil and gas operations and summary information with respect to our estimated proved oil and gas reserves. See "Item 2. Properties – Oil and Gas Reserves."

	Year Ended December 31,		
	2003	**2002**	**2001**
Production:			
Oil (MBbls)	5,727	6,237	4,023
Gas (MMcf)	62,536	67,027	68,236
Oil and gas (MMcfe)	96,898	104,449	92,374
Average prices: (1)			
Oil (per Bbl)	$30.41	$25.00	$25.62
Gas (per Mcf)	5.34	3.31	4.29
Oil and gas (per Mcfe)	5.25	3.61	4.28
Expenses (per Mcfe):			
Normal lease operating expenses (2)	$0.63	$0.58	$0.51
Salaries, general and administrative expenses	0.15	0.13	0.14
DD&A expense on oil and gas properties	1.73	1.52	1.70
Proved Reserves at December 31:			
Oil (MBbls)	59,162	52,019	55,391
Gas (MMcf)	461,323	438,652	442,669
Oil and gas (MMcfe)	816,295	750,766	775,015

(1) Includes the settlement of hedging contracts.
(2) Excludes major maintenance expenses.

2003 Compared to 2002. For the year 2003, we reported net income totaling $134.5 million, or $5.07 per share, compared to net income for the year ended December 31, 2002 of $55.4 million, or $2.09 per share. The variance in annual results was due to the following components:

Production. During 2003, production volumes decreased 7% to 96.9 Bcfe compared to 104.4 Bcfe produced during 2002. Oil production during 2003 totaled approximately 5.7 million barrels compared to 2002 oil production of 6.2 million barrels, while natural gas production during 2003 totaled approximately 62.5 billion cubic feet compared to 67.0 billion cubic feet produced during 2002. The decrease in overall 2003 production, compared to 2002, was primarily the result of delays in initial production from certain discoveries made in 2003 combined with production shut-ins for weather and rig mobilization and from natural production declines.

Prices. Prices realized during 2003 averaged $30.41 per barrel of oil and $5.34 per Mcf of gas compared to 2002 average realized prices of $25.00 per barrel of oil and $3.31 per Mcf of gas. On a gas equivalent basis, average 2003 prices were 45% higher than prices realized during 2002. All unit pricing amounts include the settlement of hedging contracts.

From time to time, we enter into various hedging contracts in order to reduce our exposure to the possibility of declining oil and gas prices. During 2003, hedging transactions decreased the average price we received for natural gas by $0.03 per Mcf, compared to a net increase of $0.13 per barrel and a net increase of $0.08 per Mcf realized during 2002. We had no hedges in place for 2003 oil production.

Oil and Gas Revenue. As a result of 45% higher realized prices on a gas equivalent basis, offset in part by a 7% decline in production, oil and gas revenue increased 35% to $508.3 million in 2003 from $377.5 million during 2002.

Expenses. During 2003, we incurred normal lease operating expenses of $61.4 million, compared to $61.0 million incurred during 2002. On a unit of production basis, 2003 normal lease operating expenses were $0.63 per Mcfe as compared to $0.58 per Mcfe for 2002.

Major maintenance expenses, which represent unpredictable repairs and maintenance costs that vary from year to year, totaled $11.4 million in 2003 compared to $15.7 million in 2002.

Effective January 1, 2003, management elected to change to the Units of Production (UOP) method of amortizing proved oil and gas property costs from the formerly used Future Gross Revenue (FGR) method. Under the UOP method, the quarterly provision for depreciation, depletion and amortization (DD&A) is computed by dividing production volumes for the period by the total proved reserves, and applying the respective rate to the net cost of proved oil and gas properties, including future development costs. Under the FGR method, the DD&A rate was calculated by dividing revenue for the period by future gross revenue. Management believes that this change in method is preferable because it removes fluctuations in DD&A expense caused by product pricing volatility within a reporting period and is a method more widely used in the oil and gas industry. The cumulative effect of the change in accounting principle of $4.0 million, net of tax, was recorded as a charge during 2003.

DD&A expense on oil and gas properties under the UOP method for 2003 totaled $168.0 million, or $1.73 per Mcfe. Under the FGR method, DD&A expense during 2002 was $158.3 million, or $1.52 per Mcfe. DD&A expense, as adjusted for the new method of accounting, would have been $166.9 million, or $1.60 per Mcfe, for 2002. The increase in DD&A per Mcfe is attributable to the unit cost of current year reserve additions, including increases in future development costs, exceeding the per unit amortizable base as of the beginning of the year. DD&A under the FGR method for the year ended December 31, 2002 was positively impacted by higher period-end oil and gas prices for 2002. See **Accounting Matters and Critical Accounting Policies – Changes in Accounting Principles.**

During 2003, we incurred $6.3 million of accretion expense related to the January 1, 2003 adoption of Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations."

Due to our progress in reaching certain of our annual performance goals, incentive compensation expense increased to $2.6 million during 2003 compared to $0.9 million during 2002.

Derivative expenses represent primarily the cost of put contracts charged to earnings as the contracts settle during the respective periods. During 2003, we incurred derivative expenses of $8.7 million compared to $16.0 million in 2002. The decline in derivative expenses in 2003 is the result of no oil put contracts for 2003 production volumes and a lower cost of our natural gas put contracts.

Effective September 30, 2003, we redeemed our outstanding $100 million aggregate principal amount of 8¾% Senior Subordinated Notes due 2007 with cash and borrowings available under our bank credit facility. As a result of the redemption of these Notes and repayments on the bank credit facility of $61.0 million, interest expense during 2003 was 17% lower than 2002. Interest expense for 2003 totaled $19.1 million, net of $8.6 million of capitalized interest, compared to interest of $23.1 million, net of $8.5 million of capitalized interest, during 2002.

Reserves. At December 31, 2003, our estimated proved oil and gas reserves totaled 816.3 Bcfe, compared to December 31, 2002 reserves of 750.8 Bcfe. The 9% increase in estimated proved reserves during 2003 was the combined result of drilling results and acquisitions made during the year. Estimated proved natural gas reserves totaled 461.3 Bcf and estimated proved oil reserves totaled 59.2 MMBbls at the end of 2003. The reserve estimates were prepared by independent petroleum consultants in accordance with guidelines established by the SEC.

Our present values of estimated future net cash flows before income taxes were $2.4 billion and $1.8 billion at December 31, 2003 and 2002, respectively. You should not assume that the present values of estimated future net cash flows represent the fair value of our estimated oil and natural gas reserves. As required by the SEC, we determine the present value of estimated future net cash flows using market prices for oil and gas on the last day of the fiscal period. The average year-end oil and gas prices on all of our properties used in determining these amounts, excluding the effects of hedges in place at year-end, were $31.79 per barrel and $6.30 per Mcf for 2003 and $30.41 per barrel and $4.86 per Mcf for 2002.

2002 Compared to 2001. For the year 2002, we reported net income totaling $55.4 million, or $2.09 per share, compared to net loss for the year ended December 31, 2001 of $71.4 million, or $2.73 per share. The variance in annual results was due to the following components:

Production. During 2002, production volumes increased 13% to 104.4 Bcfe compared to 92.4 Bcfe produced during 2001. Oil production during 2002 increased 55% to approximately 6.2 million barrels compared to 2001 oil production of 4.0 million barrels, while natural gas production during 2002 totaled approximately 67.0 billion cubic feet compared to 68.2 billion cubic feet produced during 2001. The increase in overall 2002 production, compared to 2001, was primarily the result of our December 31, 2001 acquisition of eight producing properties from Conoco, Inc.

Prices. Prices realized during 2002 averaged $25.00 per barrel of oil and $3.31 per Mcf of gas compared to 2001 average realized prices of $25.62 per barrel of oil and $4.29 per Mcf of gas. On a gas equivalent basis, average 2002 prices were 16% lower than prices realized during 2001. All unit pricing amounts include the cash effects of hedging.

From time to time, we enter into various hedging contracts in order to reduce our exposure to the possibility of declining oil and gas prices. Hedging transactions increased the average price we received during 2002 for oil by $0.13 per barrel and increased the average price we received for natural gas by $0.08 per Mcf, compared to a net increase of $0.37 per barrel and a net decrease of $0.04 per Mcf realized during 2001.

Oil and Gas Revenue. As a result of lower realized prices, offset in part by a 13% growth in production, oil and gas revenue declined 5% to $377.5 million in 2002 from $395.5 million during 2001.

Expenses. During 2002, we incurred normal lease operating expenses of $61.0 million, compared to $47.6 million incurred during 2001. On a unit of production basis, 2002 normal lease operating expenses were $0.58 per Mcfe as compared to $0.51 per Mcfe for 2001. Our December 2001 acquisition of eight producing properties increased the number of producing wells and significantly increased the volume of oil production from 2001 levels. The combination of these factors contributed to the increase in normal lease operating expenses during 2002.

Production taxes for 2002 decreased to $5.0 million from $6.4 million in 2001 primarily due to decreased production volumes from onshore properties and a decrease in the Louisiana severance tax rate for natural gas effective July 1, 2002.

Depreciation, depletion and amortization (DD&A) expense on oil and gas properties totaled $158.3 million, or $1.52 per Mcfe, during 2002 compared to $157.2 million, or $1.70 per Mcfe, for 2001. DD&A for the year ended December 31, 2002 was positively impacted by higher period-end oil and gas prices for 2002.

We follow the full cost method of accounting for oil and gas properties. Based upon low oil and gas prices at the end of the third quarter of 2001, we recognized a ceiling test write-down of our oil and gas properties totaling $237.7 million, or $154.5 million after taxes. This expense did not impact our cash flow from operating activities, but did reduce net income.

Interest expense for 2002 increased to $23.1 million, compared to $4.9 million during 2001 due to the issuance of the 8¼% Senior Subordinated Notes and borrowings under our bank credit facility to finance our $300 million acquisition in December 2001.

Due to Enron Corp's financial difficulties, during the fourth quarter of 2001, we recorded a 100% allowance for a production accounts receivable due from Enron North America Corp. This allowance resulted in a 2001 non-cash charge of approximately $2.3 million to bad debt expense.

Our merger with Basin Exploration, Inc. was completed on February 1, 2001. In connection with the completion of the merger, we incurred expenses during 2001 totaling $25.8 million.

Reserves. At December 31, 2002, our estimated proved oil and gas reserves totaled 750.8 Bcfe, compared to December 31, 2001 reserves of 775.0 Bcfe. The 3% decline in estimated proved reserves during 2002 was the combined result of 2002's record production, the exploration portion of our drilling program providing less than expected reserve additions and the lack of a material acquisition during 2002. Estimated proved natural gas reserves totaled 438.7 Bcf and estimated proved oil reserves totaled 52.0 MMBbls at the end of 2002. The reserve estimates were prepared by independent petroleum consultants in accordance with guidelines established by the SEC.

Our present values of estimated future net cash flows before income taxes were $1.8 billion and $1.0 billion at December 31, 2002 and 2001, respectively. You should not assume that the present values of estimated future net cash flows represent the fair value of our estimated oil and natural gas reserves. As required by the SEC, we determine the present value of estimated future net cash flows using market prices for oil and gas on the last day of the fiscal period. The average year-end oil and gas prices on all of our properties used in determining these amounts, excluding the effects of hedges in place at year-end, were $30.41 per barrel and $4.86 per Mcf for 2002 and $18.64 per barrel and $2.79 per Mcf for 2001.

Liquidity and Capital Resources

Cash Flow and Working Capital. Net cash flow provided by operating activities for 2003 was $391.5 million compared to $222.9 million and $315.6 million reported in 2002 and 2001, respectively. The increase in net cash flow provided by operating activities was primarily attributable to an increase oil and gas revenue generated from 45% higher average realized prices on a gas equivalent basis during 2003, offset in part by a 7% decrease in production volumes from the corresponding period. Based on our outlook of commodity prices and our estimated production, we expect to finance our 2004 capital expenditures program with cash flow from operating activities.

Net cash flow used in investing activities totaled $341.9 million, $216.6 million and $656.8 million during 2003, 2002 and 2001, respectively, which primarily represents our investment in oil and gas properties. Net cash used in investing activities in 2001 includes the $300 million acquisition of eight producing properties from Conoco.

Net cash flow provided by (used in) financing activities totaled ($60.1) million, $8.1 million and $275.8 million for the years ended December 31, 2003, 2002 and 2001, respectively. The cash flow used in financing activities during 2003 was the result of the $61.0 million of repayments under the amended credit facility. Net cash flow provided by financing activities in 2001 includes $200.0 million of proceeds from the issuance of 8¼% Senior Subordinated Notes in connection with the acquisition from Conoco. As a result of these activities, cash and cash equivalents decreased from $27.6 million as of December 31, 2002 to $17.1 million as of December 31, 2003.

We had a working capital deficit at December 31, 2003 of $38.5 million. Working capital deficits are not unusual at the end of a period, and are usually the result of accounts payable related to exploration and development costs. We believe that our working capital balance should be viewed in conjunction with availability of borrowings under our bank credit facility when measuring liquidity. Liquidity is defined as the ability to obtain cash quickly either through the conversion of assets or incurrence of liabilities. See ***Bank Credit Facility.***

Capital Expenditures. Capital expenditures during 2003 totaled $412.3 million and included $49.7 million of asset retirement costs associated with SFAS No. 143, $14.2 million of capitalized general and administrative costs, net of overhead reimbursements, and $8.6 million of capitalized interest. These investments were financed by cash flows from operating activities, borrowings under our bank credit facility and working capital.

Our 2004 capital expenditures budget, excluding acquisitions and capitalized interest and general and administrative expenses, is approximately $280.0 million, or 2% less than our 2003 capital expenditures, excluding acquisitions, asset retirement costs and capitalized interest and general and administrative expenses. Based on our outlook of commodity prices and our estimated production, we expect to finance our 2004 capital program with cash flow from operating activities.

To the extent that 2004 cash flow from operating activities exceeds our estimated 2004 capital expenditures, we plan to pay down a portion of our existing debt. If cash flow from operating activities during 2004 is not sufficient to fund estimated 2004 capital expenditures, we believe that our bank credit facility will provide us with adequate liquidity.

We do not budget acquisitions; however, we are currently evaluating opportunities that fit our specific acquisition profile. One or a combination of certain of these possible transactions could fully utilize our existing sources of capital. Although we have no plans to access the public markets for purposes of capital, if the opportunity arose, we would consider such funding sources to provide capital in excess of what is currently available to us.

Production Marketing Risk. We may not receive payment for a portion of our future production. We have attempted to diversify our sales and obtain credit protections such as letters of credit, parental guarantees and prepayments from certain of our purchasers. We are unable to predict, however, what impact the financial difficulties of certain purchasers may have on our future results of operations and liquidity.

Reserve Replacement Risk. In general, the volume of production from oil and gas properties declines as reserves are depleted. The decline rate depends on reservoir characteristics. Our proved reserves are primarily derived from Gulf of Mexico reservoirs. Gulf of Mexico reserves tend to be recovered quickly through production with associated steep declines, while declines in other regions after initial flush production tend to be relatively low. Our reserves will decline as they are produced unless we acquire properties with proved reserves or conduct successful development and exploration drilling activities. Our future natural gas and oil production, and corresponding revenues and cash flows, are highly dependent upon our level of success in finding or acquiring additional reserves. During 2003, proved reserve additions replaced 167% of our total production volumes for the year.

Bank Credit Facility. At December 31, 2003, we had $170.0 million of borrowings outstanding under our credit facility and letters of credit totaling $13.1 million had been issued pursuant to the facility. We have a borrowing base under the credit facility of $350 million, with availability of an additional $157.9 million in borrowings as of March 1, 2004. Our borrowing base under the credit facility, which is re-determined periodically, is based on an amount established by the bank group after its evaluation of our proved oil and gas reserve values.

Under the financial covenants of our credit facility, we must (i) maintain a ratio of consolidated debt to consolidated EBITDA, as defined in the amended credit agreement, for the preceding four quarterly periods of not greater than 3.25 to 1 and (ii) maintain a consolidated tangible net worth of at least $350 million, which is adjusted for future earnings and cash proceeds from equity offerings after September 30, 2001. In addition, the credit facility places certain customary restrictions or requirements with respect to disposition of properties, incurrence of additional debt, change of ownership and reporting responsibilities. These covenants may limit or prohibit us from paying cash dividends.

Hedging. See **"Item 7A. Quantitative and Qualitative Disclosure About Market Risk – Commodity Price Risk."**

Contractual Obligations and Other Commitments

The following table summarizes our significant contractual obligations and commitments, other than hedging contracts, by maturity as of December 31, 2003.

	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
			(In thousands)		
Contractual Obligations and Commitments:					
8¼% Senior Subordinated Notes due 2011...	$200,000	$ -	$ -	$ -	$200,000
Bank credit facility (1)	170,000	-	170,000	-	-
Letters of credit (1)	13,084	-	13,084	-	-
Asset retirement obligations	249,812	1,411	1,165	3,243	243,993
Operating lease obligations	1,701	954	747	-	-
Total Contractual Obligations and Commitments	$634,597	$2,365	$184,996	$3,243	$443,993

(1) The bank credit facility and related letters of credit mature on June 20, 2005.

Forward-Looking Statements

Certain of the statements set forth under this item and elsewhere in this Form 10-K are forward-looking and are based upon assumptions and anticipated results that are subject to numerous risks and uncertainties. See **"Item 1. Business — Forward-Looking Statements"** and **"— Risk Factors."**

Accounting Matters and Critical Accounting Policies

Changes in Accounting Principles. Effective January 1, 2003, management elected to change to the units of production ("UOP") method of amortizing proved oil and gas property costs from the previously used future gross revenue method. Under the UOP method, the quarterly provision for DD&A is computed by dividing production volumes, instead of revenue, for the period by the total proved reserves, instead of future gross revenue, as of the beginning of the period, and similarly applying the respective rate to the net cost of proved oil and gas properties, including future development costs. Management believes that this change in method is preferable because it removes fluctuations in DD&A expense caused by product pricing volatility within a reporting period and is a method more widely used in the oil and gas industry. As a result of the change in accounting principle, we recognized a charge against our 2003 net income for the cumulative transition adjustment of $4.0 million, net of tax.

In addition, management elected to begin recognizing production revenue under the Entitlement method of accounting effective January 1, 2003. Under this method, revenue is deferred for deliveries in excess of our net revenue interest, while revenue is accrued for the undelivered volumes. Production imbalances are generally recorded at the estimated sales price in effect at the time of production. The cumulative effect of adoption of the Entitlement method is immaterial.

Asset Retirement Obligations. In July 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 143, "Accounting for Asset Retirement Obligations," effective for fiscal years beginning after June 15, 2002. This statement requires us to record our estimate of the fair value of liabilities related to future asset retirement obligations in the period the obligation is incurred. Asset retirement obligations relate to the removal of facilities and tangible equipment at the end of an oil and gas property's useful life. The adoption of SFAS No. 143 requires the use of management's estimates with respect to future abandonment costs, inflation, market risk premiums, useful life and cost of capital. We adopted SFAS No. 143 on January 1, 2003. Upon adoption, we recognized a gain for a cumulative transition adjustment of $5.3 million, net of tax, for existing asset retirement obligation liabilities, asset retirement costs and accumulated depreciation. In addition, we recorded a $32.1 million increase in the capitalized costs of our oil and gas properties, net of accumulated depreciation, and recognized $76.3 million in additional liabilities related to asset retirement obligations. As required by SFAS No. 143, our estimate of our asset retirement obligations does not give consideration to the value the related assets could have to other parties.

Full Cost Method. We use the full cost method of accounting for our oil and gas properties. Under this method, all acquisition, exploration, development and estimated abandonment costs, including certain related employee costs and general and administrative costs (less any reimbursements for such costs), incurred for the purpose of acquiring and finding oil and gas are capitalized. Unevaluated property costs are excluded from the amortization base until we have made a determination as to the existence of proved reserves on the respective property or impairment. We review our unevaluated properties at the end of each quarter to determine whether the costs should be reclassified to the full cost pool and thereby subject to amortization. Sales of oil and gas properties are accounted for as adjustments to the net full cost pool with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves.

We amortize our investment in oil and gas properties through DD&A using the UOP method. See **"Changes in Accounting Principles"** above.

We capitalize a portion of the interest costs incurred on our debt. Capitalized interest is calculated using the amount of our unevaluated property costs and our weighted-average borrowing rate. We also capitalize the portion of employee, general and administrative expenses that are attributable to our acquisition, exploration and development activities.

Generally accepted accounting principles allow the choice of two acceptable methods for accounting for oil and gas properties. The successful efforts method is the allowable alternative to the full cost method. The primary differences between the two methods are in the treatment of exploration costs and in the computation of DD&A. Under the full cost method, all exploratory costs are capitalized while under the successful efforts method exploratory costs associated with unsuccessful exploratory wells and all geological and geophysical costs are expensed. Under full cost accounting, DD&A is computed on cost centers represented by entire countries while under successful efforts cost centers are represented by properties, fields or reservoirs.

Under the full cost method of accounting, we are required to periodically compare the present value of estimated future net cash flows from proved reserves (based on period-end commodity prices and excluding cash flows related to estimated abandonment costs), net of related tax effect, to the net capitalized costs of proved oil and gas properties, including estimated capitalized abandonment costs, net of related deferred taxes. We refer to this comparison as a "ceiling test." If the net capitalized costs of proved oil and gas properties exceed the estimated discounted future net cash flows from proved reserves, we are required to write-down the value of our oil and gas properties to the value of the discounted cash flows.

Stock-Based Compensation. In October 1995, the FASB issued SFAS No. 123, "Accounting for Stock-Based Compensation," which became effective with respect to us in 1996. Under SFAS No. 123, companies can either record expense based on the fair value of stock-based compensation upon issuance or elect to remain under the current Accounting Principles Board Opinion No. 25 ("APB 25") method whereby no compensation cost is recognized upon grant if certain requirements are met. We have continued to account for our stock-based compensation under APB 25. The Notes to Consolidated Financial Statement provide pro forma information assuming compensation expense for stock-based compensation plans had been determined consistent with the expense recognition provisions under SFAS No. 123.

Recent Accounting Developments. In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin (ARB) 51" ("FIN 46"). FIN 46 addresses consolidation by business enterprises of variable interest entities ("VIEs"). The primary objective of FIN 46 is to provide guidance on the identification of, and financial reporting for, entities over which control is achieved through means other than voting rights; such entities are known as VIEs. The provisions of FIN 46 apply immediately to VIEs created after January 31, 2003. In December 2003, the FASB issued a revision to FIN 46, which among other things, deferred the effective date for certain variable interest created prior to January 31, 2003. The Company adopted FIN 46, as revised, as of December 31, 2003, which had no impact on the financial statements.

We have taken note of a July 2003 inquiry to the Financial Accounting Standards Board regarding whether or not contract-based oil and gas mineral rights held by lease or contract ("mineral rights") should be recorded or disclosed as intangible assets. The inquiry presents a view that these mineral rights are intangible assets as defined in SFAS No. 141, "Business Combinations," and, therefore, should be classified separately on the balance sheet as intangible assets. SFAS No. 141, and SFAS No. 142, "Goodwill and Other Intangible Assets," became effective for transactions subsequent to June 30, 2001 with the disclosure requirements of SFAS No. 142

required as of January 1, 2002. SFAS No. 141 requires that intangible assets be disaggregated and reported separately from goodwill. SFAS No. 142 established new accounting guidelines for both finite lived intangible assets and indefinite lived intangible assets. Under the statement, intangible assets should be separately reported on the face of the balance sheet and accompanied by disclosure in the notes to financial statements. We do not believe that SFAS No. 141 or 142 changes the classification of oil and gas mineral rights and we continue to classify these assets as part of oil and gas properties. The Emerging Issues Task Force ("EITF") has added the treatment of oil and gas mineral rights to an upcoming agenda, which may result in a change in how we classify these assets. Since June 2001, our only significant acquisition of mineral rights was the December 2001 acquisition from Conoco totaling approximately $300 million. We estimate that of the total purchase price, approximately 70% would be classified as intangible based upon our understanding of the issue before the EITF. Using our historical DD&A rate under the UOP method, the intangible asset would be approximately $160 million, net of accumulated DD&A, as of December 31, 2003.

Based on our understanding of the issue before the EITF, if all mineral rights associated with unevaluated property and producing reserves were deemed to be intangible assets:

- mineral rights with proved reserves that were acquired after June 30, 2001 and mineral rights with no proved reserves would be classified as intangible assets and would not be included in oil and gas properties on our consolidated balance sheet;

- results of operations and cash flows would not be affected because developed mineral rights would continue to be amortized in accordance with full cost accounting rules; and

- disclosures required by SFAS Nos. 141 and 142 relative to intangibles would be included in the notes to our financial statements.

If the accounting for mineral rights is ultimately changed, transitional guidance for intangible assets permits the reclassification of only amounts acquired after the effective date of SFAS Nos. 141 and 142 if records were not previously maintained to track acquisition costs based on their intangible or tangible nature. Lack of these records prior to the effective date could result in the loss of comparability between historical balances of tangible and intangible asset balances and among companies in the industry.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates. Estimates are used primarily when accounting for DD&A, unevaluated property costs, estimated future net cash flow from proved reserves, taxes, costs to abandon oil and gas properties, reserves of accounts receivable, capitalized employee, general and administrative costs, fair value of financial instruments, the purchase price allocation on properties acquired and contingencies.

Derivative Instruments and Hedging Activities. Under SFAS No. 133, as amended, the nature of a derivative instrument must be evaluated to determine if it qualifies for hedge accounting treatment. We do not use derivative instruments for trading purposes. Instruments qualifying for hedge accounting treatment are recorded as an asset or liability measured at fair value and subsequent changes in fair value are recognized in equity through other comprehensive income, net of related taxes, to the extent the hedge is effective. Instruments not qualifying for hedge accounting treatment are recorded in the balance sheet and changes in fair value are recognized in earnings.

Deferred Income Taxes. Deferred income taxes have been determined in accordance with SFAS No. 109, "Accounting for Income Taxes." As of December 31, 2003, we had a net deferred tax liability of $127.5 million, which amount was calculated based on our assumption that it is more likely than not that we will have sufficient taxable income in future years to utilize certain tax attribute carryforwards.

For a more complete discussion of our accounting policies and procedures see our Notes to Consolidated Financial Statements beginning on page F-8.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risk, including adverse changes in commodity prices and operating costs. Assuming a 10% decline in realized oil and natural gas prices, including the effects of hedging contracts, our diluted net income per share would have declined approximately 24%. Assuming the costs to operate our properties, including lease operating and major maintenance expenses, increased 10%, our diluted earnings per share would have declined approximately 4%. These results indicate our sensitivity to changes in market conditions as it relates to commodity prices and operating costs.

Commodity Price Risk

Our revenues, profitability and future rate of growth depend substantially upon the market prices of oil and natural gas, which fluctuate widely. Oil and gas price declines and volatility could adversely affect our revenues, cash flow from operating activities and profitability. In order to manage our exposure to oil and gas price declines, we occasionally enter into oil and gas price hedging arrangements to secure a price for a portion of our expected future production. We do not enter into hedging transactions for trading purposes. While intended to reduce the effects of volatile oil and gas prices, such transactions, depending on the hedging instrument used, may limit our potential gains if oil and gas prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparties to our hedging contracts fail to perform the contracts; or
- a sudden, unexpected event materially impacts oil or natural gas prices.

Our hedging policy provides that not more than 50% of our estimated production quantities can be hedged without the consent of the board of directors.

Hedging. We realized a net decrease in revenue during 2003 from our hedging contracts of $1.6 million. During the year we hedged 37,775 BBtus of natural gas, which represented approximately 60% of our 2003 gas production. There were no oil hedges during 2003. During 2002, we realized a net increase in revenue from our hedging transactions of $6.0 million. Our contracts totaled 4,218 MBbls of oil and 24,940 BBtus of gas, which represented approximately 68% and 37%, respectively, of our oil and gas production for the year. During 2001, we realized a net decrease in revenue from our hedging transactions of $1.8 million. Our contracts totaled 1,278 MBbls of oil and 29,300 BBtus of gas, which represented approximately 32% and 43%, respectively, of our oil and gas production for the year.

Our put contracts are with Bank of America, Bank of Montreal, Bank One and J. Aron & Company (a subsidiary of Goldman Sachs). Put contracts are purchased at a rate per unit of hedged production that fluctuates with the commodity futures market. The historical cost of the put contracts represents our maximum cash exposure. We are not obligated to make any further payments under the put contracts regardless of future commodity price fluctuations. Under put contracts, monthly payments are made to us if prices fall below the agreed upon floor price, while allowing us to fully participate in commodity prices above that floor.

In October 2002, we reached an agreement with Enron North America Corp. to purchase the natural gas swap contract settling subsequent to October 2002 for $5.9 million. We amortized $3.6 million of derivative expenses during 2003 related to previously recorded other comprehensive loss from the swap contract.

During 2003, we recognized $8.7 million of derivative expenses, of which $5.1 million represents the historical cost charged to earnings associated with put contracts that settled during the year.

Because over 90% of our production has historically been derived from the Gulf Coast Basin, we believe that fluctuations in prices will closely match changes in the market prices we receive for our production. Oil contracts typically settle using the average of the daily closing prices for a calendar month. Natural gas contracts typically settle using the average closing prices for near month NYMEX futures contracts for the three days prior to the settlement date.

In addition to put contracts, we utilized fixed-price swaps to hedge a portion of our future gas production from the Rocky Mountains. Our swap contracts are with Bank of America. Swaps typically provide for monthly payments by us if prices rise above the swap price or to us if prices fall below the swap price.

The following tables show our hedging positions as of March 1, 2004:

	Put Contracts					
	Natural Gas			Oil		
	Daily Volumes (MMBtus/d)	Floor	Unamortized Cost (millions)	Daily Volumes (Bbls/d)	Floor	Unamortized Cost (millions)
2004	90,000	$3.50	$2.0	7,500	$25.00	$1.5

	Fixed Price Gas Swaps	
	Daily Volume (MMBtus/d)	Price
2004	15,000	$3.42
2005	15,000	3.42

Interest Rate Risk

On September 30, 2003, we redeemed our outstanding 8¾% Senior Subordinated Notes due 2007 with $90.0 million of borrowings under our bank credit facility and available cash. As a result, Stone had long-term debt outstanding of $370.0 million at December 31, 2003, of which $200.0 million, or approximately 54%, bears interest at a fixed rate of 8¼%. The remaining $170.0 million of debt outstanding at December 31, 2003 bears interest at a floating rate. At December 31, 2003, the weighted average interest rate under our floating-rate debt was approximately 2.6%. At December 31, 2003, we had no interest rate hedge positions in place to reduce our exposure to changes in interest rates. Assuming a 200 basis point increase in market interest rates during 2003, our interest expense, net of capitalization, would have increased approximately $1.0 million, net of taxes, resulting in a $0.01 per diluted share reduction in earnings.

Fair Value of Financial Instruments

The fair value of cash and cash equivalents, net accounts receivable, accounts payable and bank debt approximated book value at December 31, 2003. At December 31, 2003, the fair value of the 8¼% Senior Subordinated Notes due 2011 totaled $218.0 million. The fair value of the Notes has been estimated based on quotes from brokers. Our put and swap contracts are recorded on the balance sheet at fair value, which is obtained from counter-parties to the contracts.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information concerning this Item begins on Page F-1.

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

There have been no disagreements with our independent accountants on our accounting or financial reporting that would require our independent accountants to qualify or disclaim their report on our financial statements, or otherwise require disclosure in this Annual Report on Form 10-K.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our chief executive officer and our chief financial officer, with the participation of other members of our senior management, reviewed and evaluated the effectiveness of Stone's disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation, our chief executive officer and chief financial officer believe:

- Stone's disclosure controls and procedures were effective to ensure that information required to be disclosed by Stone in the reports that it files or submits 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

- Stone's disclosure controls and procedures were effective to ensure that information required to be disclosed by Stone in the reports that it files or submits under the Securities Exchange Act of 1934 was accumulated and communicated to Stone's management, including Stone's chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosure.

Internal Controls Over Financial Reporting

There has not been any change in our internal control over financial reporting that occurred during our year ended December 31, 2003 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

See **Item 4A – Executive Officers of the Registrant** for information regarding our executive officers.

Additional information required by Item 10, including information regarding our audit committee financial experts, is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2004 Annual Meeting of Stockholders to be held on May 20, 2004. The Company has made available free of charge on its Internet Web Site (www.StoneEnergy.com) the Code of Business Conduct and Ethics applicable to all employees of the Company including the chief executive officer, chief financial officer and principal accounting officer.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 11 is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2004 Annual Meeting of Stockholders to be held on May 20, 2004.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by Item 12 is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2004 Annual Meeting of Stockholders to be held on May 20, 2004.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by Item 13 is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2004 Annual Meeting of Stockholders to be held on May 20, 2004.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by Item 14 is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2004 Annual Meeting of Stockholders to be held on May 20, 2004.

PART IV

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

(a) 1. Financial Statements:

The following consolidated financial statements, notes to the consolidated financial statements and the Report of Independent Auditors thereon are included on pages F-1 through F-25 of this Form 10-K:

Report of Independent Auditors

Consolidated Balance Sheet as of December 31, 2003 and 2002

Consolidated Statement of Operations for the three years in the period ended December 31, 2003

Consolidated Statement of Cash Flows for the three years in the period ended December 31, 2003

Consolidated Statement of Changes in Stockholders' Equity for the three years in the period ended December 31, 2003

Consolidated Statement of Comprehensive Income for the three years in the period ended December 31, 2003

Notes to the 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:

3.1 -- Certificate of Incorporation of the Registrant, as amended (incorporated by reference to Exhibit 3.1 to the Registrant's Registration Statement on Form S-1 (Registration No. 33-62362)).

3.2 -- Restated Bylaws of the Registrant (incorporated by reference to Exhibit 3.2 to the Registrant's Registration Statement on Form S-1 (Registration No. 33-62362)).

3.3 -- Certificate of Amendment of the Certificate of Incorporation of Stone Energy Corporation, dated February 1, 2001 (incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K, filed February 7, 2001).

*3.4 -- Amendment to Restated Bylaws of the Registrant.

4.1 -- Rights Agreement, with exhibits A, B and C thereto, dated as of October 15, 1998, between Stone Energy Corporation and ChaseMellon Shareholder Services, L.L.C., as Rights Agent (incorporated by reference to Exhibit 4.1 to the Registrant's Registration Statement on Form 8-A (File No. 001-12074)).

4.2 -- Indenture between Stone Energy Corporation and Texas Commerce Bank, National Association dated as of September 19, 1997 (incorporated by reference to Exhibit 4.1 to the Registrant's Registration Statement on Form S-4 dated October 22, 1997 (File No. 333-38425)).

4.3 -- Amendment No. 1, dated as of October 28, 2000, to Rights Agreement dated as of October 15, 1998, between Stone Energy Corporation and ChaseMellon Shareholder Services, L.L.C., as Rights Agent (incorporated by reference to Exhibit 4.4 to the Registrant's Registration Statement on Form S-4 (Registration No. 333-51968)).

4.4 -- Indenture between Stone Energy Corporation and JPMorgan Chase Bank dated December 10, 2001 (incorporated by reference to Exhibit 4.4 to the Registrant's Registration Statement on Form S-4 (Registration No. 333-81380)).

†10.1 -- Stone Energy Corporation 1993 Nonemployee Directors' Stock Option Plan (incorporated by reference to Exhibit 10.1 to the Registrant's Registration Statement on Form S-1 (Registration No. 33-62362)).

†10.2 -- Deferred Compensation and Disability Agreements between TSPC and D. Peter Canty dated July 16, 1981, and between TSPC and Joe R. Klutts and James H. Prince dated August 23, 1981 and September 20, 1981, respectively (incorporated by reference to Exhibit 10.8 to the Registrant's Registration Statement on Form S-1 (Registration No. 33-62362)).

†10.3 -- Conveyances of Net Profits Interests in certain properties to D. Peter Canty and James H. Prince (incorporated by reference to Exhibit 10.9 to the Registrant's Registration Statement on Form S-1 (Registration No. 33-62362)).

†10.4 -- Deferred Compensation and Disability Agreement between TSPC and E. J. Louviere dated July 16, 1981 (incorporated by reference to Exhibit 10.10 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1995 (File No. 001-12074)).

†10.5 -- Stone Energy Corporation 2000 Amended and Restated Stock Option Plan (incorporated by reference to Appendix A to the Registrant's Definitive Proxy Statement on Schedule 14A for Stone's 2000 Annual Meeting of Stockholders (File No. 001-12074)).

†10.6 -- Stone Energy Corporation Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.14 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1993 (File No. 001-12074)).

†10.7 -- Stone Energy Corporation Amendment to the Annual Incentive Compensation Plan dated January 15, 1997 (incorporated by reference to Exhibit 10.9 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2000 (File No. 001-12074)).

10.8 -- Fourth Amended and Restated Credit Agreement between the Registrant, the financial institutions named therein and Bank of America, N.A., as administrative agent, dated as of December 20, 2001 (incorporated by reference to Exhibit 10.3 to the Registrant's Registration Statement on Form S-4 (Registration No. 333-81380)).

*10.9 -- Amendment No. 1 to the Fourth Amended and Restated Credit Agreement between the Registrant, the financial institutions named therein and Bank of America, N.A., as administrative agent, dated as of October 31, 2003.

†10.10 -- Stone Energy Corporation Revised Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.10 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 (File No. 001-12074)).

†10.11 -- Stone Energy Corporation 2001 Amended and Restated Stock Option Plan (incorporated by reference to Exhibit 4.1 to the Registrant's Registration Statement on Form S-8 (Registration No. 333-107440)).

16.1 -- Letter of Arthur Andersen LLP, dated June 26, 2002, regarding change in certifying accountant (incorporated by reference to Exhibit 16.1 to the Registrant's Form 8-K, filed June 27, 2002 (File No. 001-12074)).

18.1 -- Letter of Ernst & Young LLP, dated May 13, 2003, regarding change in accounting principles (incorporated by reference to Exhibit 18.1 to the Registrant's Quarterly Report on Form 10-Q, for the period ended March 31, 2003 (File No. 001-12074)).

*21.1 -- Subsidiaries of the Registrant.

*23.1 -- Consent of Ernst & Young LLP.

*23.2 -- Consent of Atwater Consultants, Ltd.

*23.3 -- Consent of Cawley, Gillespie & Associates, Inc.

*23.4 -- Consent of Ryder Scott Company, L.P.

*31.1 -- Certification of Principal Executive Officer of Stone Energy Corporation as required by Rule 13a-14(a) of the Securities Exchange Act of 1934.

*31.2 -- Certification of Principal Financial Officer of Stone Energy Corporation as required by Rule 13a-14(a) of the Securities Exchange Act of 1934.

*#32.1 -- Certification of Chief Executive Officer and Chief Financial Officer of Stone Energy Corporation pursuant to 18 U.S.C. § 1350.

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* Filed herewith.
† Identifies management contracts and compensatory plans or arrangements.
\# Not considered to be "filed" for the purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to the liabilities of that section.

(b) Reports on Form 8-K

Stone filed the following reports on Form 8-K during the fourth quarter of 2003:

Date of Event Reported	Item Reported
November 3, 2003	Items 7 & 12*
December 18, 2003	Items 7 & 9*

* The information in the Forms 8-K furnished pursuant to Items 9 & 12 is not considered to be "filed" for the purposes of Section 18 of the Exchange Act or otherwise subject to the liabilities of that section except if Stone specifically states that the information is to be considered "filed" under the Exchange Act or incorporates it by reference into a filing under the Securities Act or the Exchange Act.

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.

STONE ENERGY CORPORATION

Date: March 12, 2004

By: /s/ D. Peter Canty
D. Peter Canty
President and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ James H. Stone James H. Stone	Chairman of the Board	March 12, 2004
/s/ Joe R. Klutts Joe R. Klutts	Vice Chairman of the Board	March 12, 2004
/s/ D. Peter Canty D. Peter Canty	President, Chief Executive Officer and Director (principal executive officer)	March 12, 2004
/s/ James H. Prince James H. Prince	Senior Vice President and Chief Financial Officer (principal financial officer)	March 12, 2004
/s/ J. Kent Pierret J. Kent Pierret	Vice President, Chief Accounting Officer and Treasurer (principal accounting officer)	March 12, 2004
/s/ Peter K. Barker Peter K. Barker	Director	March 12, 2004
/s/ Robert A. Bernhard Robert A. Bernhard	Director	March 12, 2004
/s/ George R. Christmas George R. Christmas	Director	March 12, 2004
/s/ B.J. Duplantis B.J. Duplantis	Director	March 12, 2004
/s/ Raymond B. Gary Raymond B. Gary	Director	March 12, 2004
/s/ John P. Laborde John P. Laborde	Director	March 12, 2004
/s/ Richard A. Pattarozzi Richard A. Pattarozzi	Director	March 12, 2004
/s/ David R. Voelker David R. Voelker	Director	March 12, 2004

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT AUDITORS

To the Stockholders of
Stone Energy Corporation:

We have audited the accompanying consolidated balance sheets of Stone Energy Corporation (a Delaware corporation) as of December 31, 2003 and 2002, and the related consolidated statements of operations, stockholders' equity, comprehensive income and cash flows for each of the three 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.

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 Stone Energy Corporation as of December 31, 2003 and 2002, and the consolidated results of its operations and its cash flows for each of the three 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, 2001, the Company adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" and effective January 1, 2003, the Company adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." As also discussed in Note 1 to the consolidated financial statements, effective January 1, 2003, the Company elected to change to the units of production method of amortizing proved oil and gas property costs and elected to begin recognizing production revenue under the entitlement method.

Ernst & Young LLP

New Orleans, Louisiana
February 27, 2004

STONE ENERGY CORPORATION
CONSOLIDATED BALANCE SHEET
(Dollar amounts in thousands, except per share amounts)

	December 31,	
ASSETS	**2003**	**2002**
Current assets:		
Cash and cash equivalents	$17,100	$27,609
Accounts receivable	75,066	74,800
Fair value of put contracts	1,040	859
Other current assets	4,874	3,601
Total current assets	98,080	106,869
Oil and gas properties—full cost method of accounting:		
Proved, net of accumulated depreciation, depletion and amortization of $1,319,337 and $1,177,024, respectively	1,210,333	940,463
Unevaluated	107,600	107,473
Building and land, net of accumulated depreciation of $874 and $735, respectively	5,202	5,238
Fixed assets, net of accumulated depreciation of $13,029 and $11,028, respectively	5,269	5,452
Other assets, net of accumulated depreciation and amortization of $2,806 and $3,253, respectively	7,793	13,876
Total assets	$1,434,277	$1,179,371
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable to vendors	$87,646	$72,012
Undistributed oil and gas proceeds	30,793	29,027
Fair value of swap contract	7,336	-
Other accrued liabilities	10,779	7,043
Total current liabilities	136,554	108,082
Long-term debt	370,000	431,000
Deferred taxes	130,935	59,604
Asset retirement obligations	78,877	-
Fair value of swap contract	4,770	-
Other long-term liabilities	2,864	3,197
Total liabilities	724,000	601,883
Commitments and contingencies	-	-
Common stock, $.01 par value; authorized 100,000,000 shares; issued 26,432,422 and 26,337,532 shares, respectively	264	263
Treasury stock (29,882 and 32,882 shares, respectively, at cost)	(1,550)	(1,706)
Additional paid-in capital	455,391	453,176
Retained earnings	264,935	130,523
Accumulated other comprehensive loss	(8,763)	(4,768)
Total stockholders' equity	710,277	577,488
Total liabilities and stockholders' equity	$1,434,277	$1,179,371

The accompanying notes are an integral part of this balance sheet.

STONE ENERGY CORPORATION
CONSOLIDATED STATEMENT OF OPERATIONS
(Amounts in thousands, except per share amounts)

	Year Ended December 31,		
	2003	2002	2001
Operating revenue:			
Oil production	$174,139	$155,913	$103,053
Gas production	334,166	221,582	292,446
Total operating revenue	508,305	377,495	395,499
Operating expenses:			
Normal lease operating expenses	61,382	60,952	47,564
Major maintenance expenses	11,404	15,721	6,508
Production taxes	5,975	5,039	6,408
Depreciation, depletion and amortization	170,845	160,762	158,893
Accretion expense	6,292	-	-
Write-down of oil and gas properties	-	-	237,741
Salaries, general and administrative expenses	14,870	13,190	13,004
Incentive compensation expense	2,636	851	523
Derivative expense	8,711	15,968	2,604
Bad debt expense	-	-	2,343
Total operating expenses	282,115	272,483	475,588
Income (loss) from operations	226,190	105,012	(80,089)
Other (income) expenses:			
Interest	19,132	23,111	4,895
Other income	(3,133)	(3,328)	(2,997)
Other expense	538	-	-
Early extinguishment of debt	4,661	-	-
Merger expenses	-	-	25,785
Total other expenses	21,198	19,783	27,683
Net income (loss) before income taxes	204,992	85,229	(107,772)
Income tax provision (benefit):			
Current	-	-	(489)
Deferred	71,747	29,830	(35,908)
Total income taxes	71,747	29,830	(36,397)
Income (loss) before cumulative effects of accounting changes, net of tax	133,245	55,399	(71,375)
Cumulative effect of accounting changes, net of tax of $659	1,225	-	-
Net income (loss)	$134,470	$55,399	($71,375)
Earnings (loss) per common share:			
Income before cumulative effects of accounting changes	$5.05	$2.10	($2.73)
Cumulative effects of accounting changes	0.05	-	-
Earnings (loss) per common share	$5.10	$2.10	($2.73)
Earnings (loss) per common share assuming dilution:			
Income before cumulative effects of accounting changes	$5.02	$2.09	($2.73)
Cumulative effects of accounting changes	0.05	-	-
Earnings (loss) per common share assuming dilution	$5.07	$2.09	($2.73)
Average shares outstanding	26,353	26,326	26,111
Average shares outstanding assuming dilution	26,546	26,494	26,111

The accompanying notes are an integral part of this statement.

STONE ENERGY CORPORATION
CONSOLIDATED STATEMENT OF CASH FLOWS
(Dollar amounts in thousands)

	Year Ended December 31,		
	2003	2002	2001
Cash flows from operating activities:			
Net income (loss)	$134,470	$55,399	($71,375)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	170,845	160,762	158,893
Accretion expense	6,292	-	-
Deferred income tax provision (benefit)	71,747	29,830	(35,908)
Non-cash effect of production payments	(11)	(2,988)	(6,199)
Write-down of oil and gas properties	-	-	237,741
Cumulative effect of accounting changes	(1,225)	-	-
Early extinguishment of debt	1,744	-	-
Derivative expenses	8,711	15,968	2,604
Other non-cash expenses	533	706	1,002
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	(266)	(27,813)	48,735
(Increase) decrease in other current assets	538	(253)	733
Increase (decrease) in other accrued liabilities	4,091	6,495	(13,279)
Investment in derivative contracts	(2,932)	(15,301)	(6,466)
Settlement of asset retirement obligations	(2,965)	-	-
Other	(33)	116	(864)
Net cash provided by operating activities	391,539	222,921	315,617
Cash flows from investing activities:			
Investment in oil and gas properties	(340,516)	(213,566)	(657,327)
Sale of proved properties	475	3,304	-
Sale of unevaluated properties	-	600	1,366
Building additions and renovations	(103)	(23)	-
Increase in other assets	(1,764)	(6,915)	(886)
Net cash used in investing activities	(341,908)	(216,600)	(656,847)
Cash flows from financing activities:			
Proceeds from borrowings	100,000	22,000	131,000
Repayment of debt	(61,000)	(17,000)	(53,000)
Redemption of 8¾% senior subordinated notes	(100,000)	-	-
Proceeds from issuance of 8¼% senior subordinated notes	-	-	200,000
Deferred financing costs	(582)	(287)	(6,794)
Proceeds from exercise of stock options	1,442	3,420	4,822
Purchase of treasury stock	-	-	(200)
Net cash provided by (used in) financing activities	(60,140)	8,133	275,828
Net increase (decrease) in cash and cash equivalents	(10,509)	14,454	(65,402)
Cash and cash equivalents, beginning of year	27,609	13,155	78,557
Cash and cash equivalents, end of year	$17,100	$27,609	$13,155
Supplemental disclosures of cash flow information:			
Cash paid during the year for:			
Interest (net of amount capitalized)	$22,898	$22,495	$3,992
Income taxes	-	-	-

The accompanying notes are an integral part of this statement.

STONE ENERGY CORPORATION
CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY
(Dollar amounts in thousands)

	Common Stock	Treasury Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
Balance, December 31, 2000	$260	$ -	$440,729	$146,588	$ -	$587,577
Net loss	-	-	-	(71,375)	-	(71,375)
Cumulative effect of accounting change for derivatives, net of tax benefit	-	-	-	-	(26,114)	(26,114)
Net change in fair value of derivatives, net of taxes	-	-	-	-	33,720	33,720
Effect of change in accounting treatment for swaps, net of tax benefit	-	-	-	-	(110)	(110)
Exercise of stock options	2	-	6,677	-	-	6,679
Tax benefit from stock option exercises	-	-	1,499	-	-	1,499
Purchase of treasury stock	-	(2,057)	-	-	-	(2,057)
Issuance and vesting of restricted stock	-	-	206	-	-	206
Balance, December 31, 2001	262	(2,057)	449,111	75,213	7,496	530,025
Net income	-	-	-	55,399	-	55,399
Net change in fair value of derivatives, net of tax benefit	-	-	-	-	(14,012)	(14,012)
Effect of accounting treatment for swaps, net of taxes	-	-	-	-	1,748	1,748
Exercise of stock options	1	-	3,332	-	-	3,333
Tax benefit from stock option exercises	-	-	733	-	-	733
Issuance of treasury stock	-	351	-	(89)	-	262
Balance, December 31, 2002	263	(1,706)	453,176	130,523	(4,768)	577,488
Net income	-	-	-	134,470	-	134,470
Net change in fair value of derivatives, net of tax benefit	-	-	-	-	(6,356)	(6,356)
Effect of accounting treatment for swaps, net of taxes	-	-	-	-	2,361	2,361
Exercise of stock options	1	-	1,441	-	-	1,442
Tax benefit from stock option exercises	-	-	774	-	-	774
Issuance of treasury stock	-	156	-	(58)	-	98
Balance, December 31, 2003	$264	($1,550)	$455,391	$264,935	($8,763)	$710,277

The accompanying notes are an integral part of this statement.

STONE ENERGY CORPORATION
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
(Dollar amounts in thousands)

	Year Ended December 31,		
	2003	**2002**	**2001**
Net income (loss)	$134,470	$55,399	($71,375)
Other comprehensive income (loss):			
Cumulative effect of accounting change for derivatives, net of tax benefit	-	-	(26,114)
Net change in fair value of derivatives, net of taxes	(6,356)	(14,012)	33,720
Effect of change in accounting treatment for swaps, net of taxes	2,361	1,748	(110)
Other comprehensive income (loss)	(3,995)	(12,264)	7,496
Comprehensive income (loss)	$130,475	$43,135	($63,879)

The accompanying notes are an integral part of this statement.

(Dollar amounts in thousands, except per share and price amounts)

NOTE 1 — ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Stone Energy Corporation is an independent oil and gas company engaged in the acquisition, exploration, development, production and operation of oil and gas properties in the Gulf Coast Basin and Rocky Mountains. The Gulf Coast Basin represents our primary focal area of operation and has been throughout our existence.

Our headquarters are in Lafayette, Louisiana, with additional offices in New Orleans, Louisiana, Houston, Texas and Denver, Colorado.

A summary of significant accounting policies followed in the preparation of the accompanying consolidated financial statements is set forth below.

Merger with Basin Exploration:

On February 1, 2001, the stockholders of Stone Energy Corporation and Basin Exploration, Inc. ("Basin") voted in favor of, and thereby consummated, the combination of the two companies in a tax-free, stock-for-stock transaction accounted for under the Pooling-of-Interests method. Stone issued 7,436,652 shares of common stock. In addition, Stone assumed, and subsequently retired with cash on hand, $48,000 of Basin bank debt. The expenses incurred in relation to the merger totaled $25,785 in 2001.

Basis of Presentation:

The financial statements include our accounts and the accounts of our wholly owned subsidiary. All intercompany balances have been eliminated. Certain prior year amounts have been reclassified to conform to current year presentation.

Use of Estimates:

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the 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. Estimates are used primarily when accounting for depreciation, depletion and amortization, unevaluated property costs, estimated future net cash flows from proved reserves, cost to abandon oil and gas properties, taxes, reserves of accounts receivable, accrual of operating costs and production revenue, capitalized employee, general and administrative expenses, effectiveness of financial instruments, the purchase price allocation on properties acquired and contingencies.

Fair Value of Financial Instruments:

The fair value of cash and cash equivalents, accounts receivable, accounts payable to vendors and our variable-rate bank debt approximated book value at December 31, 2003 and 2002. Our hedging contracts, including puts and swaps, are recorded in the financial statements at fair value in accordance with the Financial Accounting Standards Board's ("FASB") Statement of Financial Accounting Standard ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities." The following table presents the carrying amounts and estimated fair values of our financial instruments at December 31, 2003 and 2002.

	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
8¼% Senior Subordinated Notes due 2011	$200,000	$218,000	$200,000	$208,000
8¾% Senior Subordinated Notes due 2007 (1)	-	-	100,000	103,500

(1) Redeemed on September 30, 2003. See **Note 7 – Long-Term Debt.**

The following methods and assumptions were used to estimate the fair value of the financial instruments detailed above. The carrying amount of the bank debt approximated fair value because the interest rate is variable and reflective of market rates. The fair value of the Notes has been estimated based on quotes obtained from brokers.

Cash and Cash Equivalents:

We consider all money market funds and highly liquid investments in overnight securities through our commercial bank accounts, which result in available funds on the next business day, to be cash and cash equivalents.

Oil and Gas Properties:

We follow the full cost method of accounting for oil and gas properties. Under this method, all acquisition, exploration, development and estimated abandonment costs, including certain related employee and general and administrative costs (less any reimbursements for such costs) and interest incurred for the purpose of finding oil and gas are capitalized. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals and other costs related to such activities. Employee, general and administrative costs that are capitalized include salaries and all related fringe benefits paid to employees directly engaged in the acquisition, exploration and development of oil and gas properties, as well as all other directly identifiable general and administrative costs associated with such activities, such as rentals, utilities and insurance. Fees received from managed partnerships for providing such services are accounted for as a reduction of capitalized costs. Employee, general and administrative costs associated with production operations and general corporate activities are expensed in the period incurred. Additionally, workover costs incurred solely to maintain or increase levels of production from an existing completion interval are charged to expense in the period incurred.

Under the full cost method of accounting, we are required to periodically compare the present value of estimated future net cash flows from proved reserves (based on period-end commodity prices and excluding cash flows related to estimated abandonment costs), net of related tax effect, to the net capitalized costs of proved oil and gas properties, including estimated capitalized abandonment costs, net of related deferred taxes. We refer to this comparison as a "ceiling test." If the net capitalized costs of proved oil and gas properties exceed the estimated discounted future net cash flows from proved reserves, we are required to write-down the value of our oil and gas properties to the value of the discounted cash flows. Due to the impact of low natural gas prices on September 30, 2001, we recorded a $237,741 reduction in the carrying value of our oil and gas properties.

Effective January 1, 2003, management elected to change to the units of production ("UOP") method of amortizing proved oil and gas property costs from the previously used future gross revenue method. Under the UOP method, the quarterly provision for DD&A is computed by dividing production volumes, instead of revenues, for the period by the total proved reserves, instead of future gross revenues, as of the beginning of the period, and similarly applying the respective rate to the net cost of proved oil and gas properties, including future development costs. Management believes that this change in method is preferable because it removes fluctuations in DD&A expense caused by product pricing volatility within a reporting period and is a method more widely used in the oil and gas industry. As a result of the change in accounting principle, we recognized a cumulative transition adjustment of $4,031, net of tax, as a charge against our 2003 net income. Transactions involving sales of unevaluated properties are recorded as adjustments to oil and gas properties and sales of reserves in place, unless extraordinarily large portions of reserves are involved, are recorded as adjustments to accumulated depreciation, depletion and amortization.

During the years ended December 31, 2002 and 2001, our investment in oil and gas properties was amortized through DD&A using the future gross revenue method whereby the annual provision is computed by dividing revenue earned during the period by future gross revenues at the beginning of the period, and applying the resulting rate to the cost of oil and gas properties, including estimated future development, restoration, dismantlement and abandonment costs. Assuming the future gross revenue method was utilized during 2003, net income, diluted earnings per share and DD&A per Mcfe would have totaled $141,714, $5.34 and $1.68, respectively. The following table illustrates the effects that the change in accounting for DD&A would have had on prior periods assuming adoption of the UOP method as of the beginning of the earliest period presented:

	Year Ended December 31,			
	2002		2001	
	As Reported	Pro Forma (Unaudited)	As Reported	Pro Forma (Unaudited)
Net income (loss)	$55,399	$49,768	($71,375)	($51,591)
Diluted earnings (loss) per share	$2.09	$1.88	($2.73)	($1.98)
DD&A per Mcfe	$1.52	$1.60	$1.70	$1.60

Oil and gas properties included $107,600 and $107,473 of unevaluated property and related costs that were not being amortized at December 31, 2003 and 2002, respectively. We believe that a majority of unevaluated properties at December 31, 2003 will be evaluated within 48 months. The excluded costs will be included in the amortization base as the properties are evaluated and proved reserves are established or impairment is determined. Interest capitalized on unevaluated properties during the years ended December 31, 2003, 2002 and 2001 was $8,577, $8,519 and $6,000, respectively.

On December 31, 2001, Stone completed the acquisition of eight producing oil and gas properties and related assets located in the Gulf of Mexico from Conoco, Inc. This acquisition totaled $300,000 and was accounted for under the purchase method of accounting. Unevaluated property at December 31, 2003 and 2002 included $52,760 and $55,160, respectively, of costs attributable to these properties.

Building and Land:

Building and land are recorded at cost. Our Lafayette office building is being depreciated on the straight-line method over its estimated useful life of 39 years.

Fixed Assets:

Fixed assets at December 31, 2003 and 2002 included approximately $3,603 and $3,553, respectively, of computer hardware and software costs, net of accumulated depreciation. These costs are being depreciated on the straight-line method over an estimated useful life of five years.

Other Assets:

Other assets at December 31, 2003 and 2002 included approximately $5,796 and $8,257, respectively, of deferred financing costs, net of accumulated amortization, related primarily to the issuance of the 8¾% and 8¼% Notes and the amendment of the credit facility (see **Note 7 – Long-Term Debt**). In connection with the redemption of our 8¾% Notes on September 30, 2003, we recognized a charge for the early extinguishment of debt of $4,661 during 2003, which included the redemption premium of $2,917 and the recognition of previously deferred financing costs and unamortized discounts associated with the issuance of the Notes in 1997. The costs associated with the 8¼% Notes are being amortized over the life of the Notes using the effective interest method. The costs associated with the credit facility are being amortized on the straight-line method over the term of the facility.

Earnings Per Common Share:

Basic net income per share of common stock was calculated by dividing net income applicable to common stock by the weighted-average number of common shares outstanding during the year. Diluted net income per share of common stock was calculated by dividing net income applicable to common stock by the weighted-average number of common shares outstanding during the year plus the weighted-average number of outstanding dilutive stock options granted to outside directors, officers and employees. There were approximately 193,000 and 168,000 weighted-average dilutive shares for the years ending December 31, 2003 and 2002, respectively. Options that were considered antidilutive because the exercise price of the stock exceeded the average price for the applicable period totaled approximately 1,021,000 shares and 1,064,000 shares during 2003 and 2002, respectively. In 2001, all stock options were considered antidilutive because of the net loss incurred during the year.

Production Revenue:

Effective January 1, 2003, management elected to begin recognizing production revenue under the Entitlement method of accounting. Under this method, revenue is deferred for deliveries in excess of the company's net revenue interest, while revenue is accrued for the undelivered volumes. Production imbalances are generally recorded at the estimated sales price in effect at the time of production. The cumulative effect of the adoption of the Entitlement method recognized in 2003 is immaterial.

Prior to adopting the Entitlement method, we recorded as revenue only that portion of production sold and allocable to our ownership interest in the related well. Any production proceeds received in excess of our ownership interest were reflected as a liability in the accompanying balance sheet. Revenue relating to net undelivered production to which we are entitled but for which we had not received payment were not recorded in the financial statements until such amounts were received. These amounts at December 31, 2002 and 2001 were immaterial.

Income Taxes:

Income taxes are accounted for in accordance with the SFAS No. 109, "Accounting for Income Taxes." Provisions for income taxes include deferred taxes resulting primarily from temporary differences due to different reporting methods for oil and gas properties for financial reporting purposes and income tax purposes. For financial reporting purposes, all exploratory and development expenditures, including future abandonment costs, related to evaluated projects are capitalized and depreciated, depleted and amortized on the units 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, we follow certain provisions of the Internal Revenue Code that allow capitalization of intangible drilling costs where management deems appropriate. Other financial and income tax reporting differences occur as a result of statutory depletion, different reporting methods for sales of oil and gas reserves in place, and different reporting methods used in the capitalization of employee, general and administrative and interest expenses.

New Accounting Standard:

In July 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations," effective for fiscal years beginning after June 15, 2002. This statement requires us to record the fair value of liabilities related to estimated future asset retirement obligations in the period the obligation is incurred. We adopted SFAS No. 143 on January 1, 2003. Upon adoption, we recognized a credit for a cumulative transition adjustment of $5,256, net of tax, for existing asset retirement obligation liabilities, asset retirement costs and accumulated depreciation. In addition, we recorded a $32,080 increase in the capitalized costs of our oil and gas properties, net of accumulated depreciation, and recognized $76,270 in additional liabilities related to asset retirement obligations. As required by SFAS No. 143, our estimate of our asset retirement obligation does not give consideration to the value the related assets could have to other parties. See **Note 5 – Asset Retirement Obligations**.

Recent Accounting Developments:

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin (ARB) 51" ("FIN 46"). FIN 46 addresses consolidation by business enterprises of variable interest entities ("VIEs"). The primary objective of FIN 46 is to provide guidance on the identification of, and financial reporting for, entities over which control is achieved through means other than voting rights; such entities are known as VIEs. The provisions of FIN 46 apply immediately to VIEs created after January 31, 2003. In December 2003, the FASB issued a revision to FIN 46, which among other things, deferred the effective date for certain variable interest created prior to January 31, 2003. The Company adopted FIN 46, as revised, as of December 31, 2003, which had no impact on the financial statements.

We have taken note of a July 2003 inquiry to the FASB regarding whether or not contract-based oil and gas mineral rights held by lease or contract ("mineral rights") should be recorded or disclosed as intangible assets. The inquiry presents a view that these mineral rights are intangible assets as defined in SFAS No. 141, "Business Combinations," and, therefore, should be classified separately on the balance sheet as intangible assets. SFAS No. 141, and SFAS No. 142, "Goodwill and Other Intangible Assets," became effective for transactions subsequent to June 30, 2001 with the disclosure requirements of SFAS No. 142 required as of January 1, 2002. SFAS No. 141 requires that intangible assets be disaggregated and reported separately from goodwill. SFAS No. 142 established new accounting guidelines for both finite lived intangible assets and indefinite lived intangible assets. Under the statement, intangible assets should be separately reported on the face of the balance sheet and accompanied by disclosure in the notes to financial statements. We do not believe that SFAS No. 141 or 142 changes the classification of oil and gas mineral rights and we continue to classify these assets as part of oil and gas properties. The Emerging Issues Task Force (EITF) has added the treatment of oil and gas mineral rights to an upcoming agenda, which may result in a change in how we classify these assets. Since June 2001, our only significant acquisition of mineral rights was the December 2001 acquisition from Conoco totaling approximately $300,000. We estimate that of the total purchase price, approximately 70% would be classified as intangible based upon our understanding of the issue before the EITF. Using our historical DD&A rate under the UOP method, the intangible asset would be approximately $160,000, net of accumulated DD&A, as of December 31, 2003.

Based on our understanding of the issue before the EITF, if all mineral rights associated with unevaluated property and producing reserves were deemed to be intangible assets:

- mineral rights with proved reserves that were acquired after June 30, 2001 and mineral rights with no proved reserves would be classified as intangible assets and would not be included in oil and gas properties on our consolidated balance sheet;

- results of operations and cash flows would not be affected because developed mineral rights would continue to be amortized in accordance with full cost accounting rules; and

- disclosures required by SFAS Nos. 141 and 142 relative to intangibles would be included in the notes to our financial statements.

If the accounting for mineral rights is ultimately changed, transitional guidance for intangible assets permits the reclassification of only amounts acquired after the effective date of SFAS Nos. 141 and 142 if records were not previously maintained to track acquisition costs based on their intangible or tangible nature. Lack of these records prior to the effective date could result in the loss of comparability between historical balances of tangible and intangible asset balances and among companies in the industry.

Derivative Instruments and Hedging Activities:

Under SFAS No. 133, as amended, the nature of a derivative instrument must be evaluated to determine if it qualifies for hedge accounting treatment. Instruments qualifying for hedge accounting treatment are recorded as an asset or liability measured at fair value and subsequent changes in fair value are recognized in equity through other comprehensive income, net of related taxes, to the extent the hedge is effective. The cash settlement of effective cash flow hedges is recorded into revenue. Instruments not qualifying for hedge accounting treatment are recorded in the balance sheet and changes in fair value are recognized in earnings as derivative expense (income). At December 31, 2003, our put and swap contracts were considered effective cash flow hedges. (See **Note 9 – Hedging Activities**)

Stock-Based Compensation:

In October 1995, the FASB issued SFAS No. 123, "Accounting for Stock-Based Compensation," which became effective with respect to us in 1996. Under SFAS No. 123, companies can either record expense based on the fair value of stock-based compensation upon issuance or elect to remain under the current Accounting Principles Board Opinion No. 25 ("APB 25") method whereby no compensation cost is recognized upon grant if certain requirements are met. We have continued to account for our stock-based compensation under APB 25.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure, an amendment of FASB Statement No. 123", to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based compensation. Additionally, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require prominent disclosure in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effects of the method used on reported results. If the compensation expense for stock-based compensation plans had been determined consistent with the expense recognition provisions under SFAS No. 123, our net income (loss) and basic and diluted earnings (loss) per common share for the years presented would have approximated the pro forma amounts below:

	Year Ended December 31,		
	2003	**2002**	**2001**
	(In thousands, except per share amounts) (Unaudited)		
Net income (loss), as reported	$134,470	$55,399	($71,375)
Add: Stock-based compensation expense included in net income, net of tax	-	-	-
Less: Stock-based compensation expense using fair value method, net of tax	(5,287)	(5,407)	(5,266)
Pro forma net income (loss)	$129,183	$49,992	($76,641)
Basic earnings per share	$5.10	$2.10	($2.73)
Pro forma basic earnings per share	4.90	1.90	(2.94)
Diluted earnings per share	$5.07	$2.09	($2.73)
Pro forma diluted earnings per share	4.87	1.89	(2.94)

NOTE 2 — ACCOUNTS RECEIVABLE:

In our capacity as operator for our co-venturers, we incur drilling and other costs that we bill to the respective parties based on their working interests. We also receive payments for these billings and, in some cases, for billings in advance of incurring costs. Our accounts receivable are comprised of the following amounts:

	December 31,	
	2003	**2002**
Accounts Receivable:		
Other co-venturers	$6,004	$10,224
Trade	68,796	64,195
Officers and employees	4	6
Unbilled accounts receivable	262	375
	$75,066	$74,800

NOTE 3 — CONCENTRATIONS:

Sales to Major Customers

Our production is sold on month-to-month contracts at prevailing prices. We have attempted to diversify our sales and obtain credit protections such as letters of credit, parental guarantees and prepayments from certain of our purchasers. The following table identifies customers from whom we derived 10% or more of our total oil and gas revenue during the following years ended:

	December 31,		
	2003	**2002**	**2001**
Cinergy Marketing and Trading	12%	-	-
Conoco, Inc.	(a)	10%	(a)
Duke Energy Trading and Marketing LLC	13%	24%	(a)
El Paso Merchant Energy, LP	(a)	(a)	26%
Enron North America Corp	-	-	19%
Equiva Trading Company	10%	(a)	(a)
Reliant Services, Inc.	-	11%	(a)

(a) Less than 10 percent

We believe that the loss of any of these purchasers would not result in a material adverse effect on our ability to market future oil and gas production.

During the fourth quarter of 2001, we recorded a $2,343 bad debt expense to reserve 100% of production accounts receivable from Enron North America Corp.

Production and Reserve Volumes

Approximately 91% of our estimated proved reserves at December 31, 2003 and 94% of our production during 2003 were associated with our Gulf Coast Basin properties.

Cash Deposits

Substantially all of our cash balances are in excess of federally insured limits.

NOTE 4 — INVESTMENT IN OIL AND GAS PROPERTIES:

The following table discloses certain financial data relative to our oil and gas producing activities located onshore and offshore the continental United States, which represents our only operating segment:

	Year Ended December 31,		
	2003	2002	2001
Oil and gas properties—			
Balance, beginning of year	$2,224,960	$2,009,361	$1,368,084
Costs incurred during the year:			
Capitalized—			
Acquisition costs, net of sales of unevaluated properties	54,456	14,071	328,778
Exploratory costs	175,864	86,063	176,679
Development costs	109,507	96,426	119,426
Employee, general and administrative costs and interest	23,002	19,603	16,720
Less: overhead reimbursements	(247)	(564)	(326)
Asset retirement costs (1)	49,728	-	-
Total costs incurred during year	412,310	215,599	641,277
Balance, end of year	$2,637,270	$2,224,960	$2,009,361
Charged to expense—			
Operating costs:			
Normal lease operating expenses	$61,382	$60,952	$47,564
Major maintenance expenses	11,404	15,721	6,508
Total operating costs	72,786	76,673	54,072
Production taxes	5,975	5,039	6,408
Accretion expense (1)	6,292	-	-
	$85,053	$81,712	$60,480
Unevaluated oil and gas properties—			
Costs incurred during year:			
Acquisition costs	$25,891	$11,872	$77,311
Exploration costs	3,843	6,238	-
	$29,734	$18,110	$77,311
Accumulated depreciation, depletion and amortization—			
Balance, beginning of year	($1,177,024)	($1,015,455)	($620,510)
Provision for depreciation, depletion and amortization	(167,990)	(158,265)	(157,204)
Asset retirement costs (1)	32,354	-	-
Cumulative effect of change in accounting	(6,202)	-	-
Sale of proved properties	(475)	(3,304)	-
Write-down of oil and gas properties	-	-	(237,741)
Balance, end of year	($1,319,337)	($1,177,024)	($1,015,455)
Net capitalized costs (proved and unevaluated)	$1,317,933	$1,047,936	$993,906
DD&A per Mcfe (2)	$1.73	$1.52	$1.70

(1) Recorded in connection with SFAS No. 143. See **Note 5 – Asset Retirement Obligations**.
(2) DD&A during 2002 and 2001 was computed on a method different than 2003. See **Note 1 – Oil and Gas Properties**.

NOTE 4 — INVESTMENT IN OIL AND GAS PROPERTIES: (Continued)

The following table discloses financial data associated with unevaluated costs at December 31, 2003:

	Balance as of December 31, 2003	Costs incurred during the year ended December 31, 2003	2002	2001	2000 and prior
Acquisition costs	$95,045	$25,891	$6,101	$45,765	$17,288
Exploration costs	12,555	3,843	244	6,694	1,774
Total unevaluated costs	$107,600	$29,734	$6,345	$52,459	$19,062

We believe that substantially all of the costs not currently subject to amortization will be evaluated within four years.

NOTE 5 – ASSET RETIREMENT OBLIGATIONS:

In July 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations," effective for fiscal years beginning after June 15, 2002. This statement requires us to record the fair value of liabilities related to future asset retirement obligations ("ARO") in the period the obligation is incurred. Asset retirement obligations relate to the removal of facilities and tangible equipment at the end of an oil and gas property's useful life. We adopted SFAS No. 143 on January 1, 2003. Upon adoption, we recognized a gain for a cumulative transition adjustment of $5,256, net of tax, computed from the components below:

Initial ARO as a liability on our consolidated balance sheet, including accumulated accretion	($76,270)
Increase in oil and gas properties for the cost to abandon our oil and gas properties	52,002
Accumulated depreciation on the additional capitalized costs included in oil and gas properties at adoption date	(19,922)
Reversal of accumulated depreciation previously recorded related to abandonment costs	52,276
Cumulative effect of adoption	8,086
Tax effect	(2,830)
Cumulative effect of adoption, net of tax effect	$5,256

In general, the amount of an ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor after discounting the future cost back to the date that the abandonment obligation was incurred using an assumed cost of funds for our company. After recording these amounts, the ARO will be accreted to its future estimated value using the same assumed cost of funds and the additional capitalized costs will be depreciated on a UOP basis. As required by SFAS No. 143, our estimate of our asset retirement obligations does not give consideration to the value the related assets could have to other parties.

The change in our ARO since adoption of SFAS No. 143 is set forth below:

Initial asset retirement obligation as of January 1, 2003	$76,270
Additional liabilities incurred	7,017
Liabilities settled	(3,068)
Accretion expense	6,292
Revision of estimates	(6,223)
Asset retirement obligation as of December 31, 2003, including current portion	$80,288

Assuming adoption of SFAS No. 143 at the earliest period presented, our net income (loss), diluted earnings (loss) per share and liability for asset retirement obligations as of the end of the year, without any cumulative effect of change in accounting principle, would have approximated the pro forma amounts below for the respective periods:

	Year Ended December 31,			
	2002		2001	
	As Reported	Pro Forma (Unaudited)	As Reported	Pro Forma (Unaudited)
Net income (loss)	$55,399	$54,881	($71,375)	($59,466)
Diluted earnings (loss) per share	$2.09	$2.07	($2.73)	($2.28)
Asset retirement obligations	$ -	$76,270	$ -	$69,771

NOTE 6 — INCOME TAXES:

An analysis of our deferred taxes follows:

	As of December 31,	
	2003	2002
Net operating loss carryforward	$33,312	$18,010
Statutory depletion carryforward	5,000	4,917
Contribution carryforward	328	276
Capital loss carryforward	63	64
Alternative minimum tax credit carryforward	812	812
Temporary differences:		
Oil and gas properties — full cost	(170,218)	(84,853)
Hedges	4,719	3,071
Other	(1,152)	(69)
Valuation allowance	(391)	(276)
	($127,527)	($58,048)

For tax reporting purposes, operating loss carryforwards totaled approximately $95,176 at December 31, 2003. If not utilized, such carryforwards would begin expiring in 2009 and would completely expire by the year 2023. In addition, we had approximately $14,805 in statutory depletion deductions available for tax reporting purposes that may be carried forward indefinitely. Recognition of a deferred tax asset associated with these carryforwards is dependent upon our evaluation that it is more likely than not that the asset will ultimately be realized.

As of December 31, 2003 and 2002, a deferred tax asset of $3,408 and $1,556, respectively was included in other current assets.

Reconciliation between the statutory federal income tax rate and our effective income tax rate as a percentage of income before income taxes follows:

	Year Ended December 31,		
	2003	2002	2001
Income tax expense (benefit) computed at the statutory federal income tax rate	35%	35%	(35%)
Non-deductible portion of merger expenses	-	-	2%
Other	-	-	(1%)
Effective income tax rate	35%	35%	(34%)

Income tax expense (benefit) allocated to accumulated other comprehensive income amounted to $2,151, $6,604 and ($4,036) for the years ended December 31, 2003, 2002 and 2001, respectively.

NOTE 7 — LONG-TERM DEBT:

Long-term debt consisted of the following at:

	December 31,	
	2003	2002
8¼% Senior subordinated notes due 2011	$200,000	$200,000
8¾% Senior subordinated notes due 2007	-	100,000
Bank debt	170,000	131,000
Total long-term debt	$370,000	$431,000

On September 30, 2003, we redeemed our $100,000 outstanding 8¾% Senior Subordinated Notes due 2007 at a call premium of 102.917%. The cash redemption payment was funded through a combination of available cash and $90,000 of borrowings under the Company's bank credit facility. The Company recorded a pre-tax charge of $4,661 during 2003 for the early extinguishment of debt, which related to the call premium of $2,917 and the recognition of previously deferred financing costs and unamortized discounts associated with the issuance of the Notes in 1997.

On December 5, 2001, we issued $200,000 8¼% Senior Subordinated Notes due 2011. The Notes were sold at par value and we received net proceeds of $195,500. There is no sinking fund requirement and the Notes are redeemable at our option, in whole but not in part, at any time before December 15, 2006 at a Make-Whole Amount. Beginning December 15, 2006, the Notes are redeemable at our option, in whole or in part, at 104.125% of their principal amount and thereafter at prices declining annually to 100% on and after December 15, 2009. In addition, before December 15, 2004, we may redeem up to 35% of the aggregate principal amount of the Notes issued with net proceeds from an equity offering at 108.25%. The Notes provide for certain covenants, which include, without limitation, restrictions on liens, indebtedness, asset sales, dividend payments and other restricted payments. At December 31, 2003, $746 had been accrued in connection with the June 15, 2004 interest payment.

At December 31, 2003, we had $170,000 of borrowings outstanding under our bank credit facility and letters of credit totaling $13,084 had been issued pursuant to the facility. The credit facility matures on June 20, 2005. At December 31, 2003, we had a borrowing base under the credit facility of $350,000, with availability of an additional $166,916 of borrowings. The weighted average interest rate under the credit facility was approximately 2.6% at December 31, 2003. Interest rates are tied to LIBOR rates plus a margin that fluctuates based upon the ratio of aggregate outstanding borrowings and letters of credit exposure to the total borrowing base. Commitment fees are computed and payable quarterly at the rate of 50 basis points of borrowing availability. The borrowing base limitation is re-determined periodically and is based on a borrowing base amount established by the banks for our oil and gas properties.

Under the financial covenants of our credit facility, we must (i) maintain a ratio of consolidated debt to consolidated EBITDA, as defined in the amended credit agreement, for the preceding four quarterly periods of not greater than 3.25 to 1 and (ii) maintain a consolidated tangible net worth of a least $350,000 as of September 30, 2001, which is adjusted for future earnings and cash proceeds from equity offerings. In addition, the credit facility places certain customary restrictions or requirements with respect to disposition of properties, incurrence of additional debt, change of ownership and reporting responsibilities. These covenants may limit or prohibit us from paying cash dividends.

NOTE 8 — TRANSACTIONS WITH RELATED PARTIES:

James H. Stone and Joe R. Klutts, both directors of Stone Energy, collectively own 9% of the working interest in certain wells drilled on Section 19 on the east flank of Weeks Island Field. These interests were acquired at the same time that our predecessor company acquired its interests in Weeks Island Field. In their capacity as working interest owners, they are required to pay their proportional share of all costs and are entitled to receive their proportional share of revenues.

Our interests in certain oil and gas properties are burdened by net profits interests and overriding royalty interests granted at the time of acquisition to certain of our officers. Such net profit interest owners do not receive any cash distributions until we have recovered all acquisition, development, financing and operating costs. D. Peter Canty, chief executive officer, and James H. Prince, chief financial officer, remain net profit interest owners. Amounts paid to these officers under the remaining net profits arrangement amounted to $1,169, $934 and $1,777 in 2003, 2002 and 2001, respectively. In addition, Michael E. Madden, our Vice President of Engineering, was granted an overriding royalty interest in some of our properties by an independent third party. At the time he was granted this interest, he was serving us as an independent engineering consultant. The amount paid to Michael E. Madden during 2003 and 2002 under the overriding royalty arrangement totaled $94 and $61. Mr. Madden was promoted to Vice President of Engineering in March of 2002.

NOTE 8 — TRANSACTIONS WITH RELATED PARTIES: (Continued)

Joe R. Klutts, one of our directors, received $17 and $56 during 2002 and 2001, respectively, in consulting fees after retiring, February 1, 2000, as an employee of Stone.

The son of John P. Laborde, one of our directors, has an interest in several marine service companies, which provided services to us during 2003, 2002 and 2001 in the amount of $2,978, $1,717 and $255, respectively. As of December 31, 2003, we had accrued $155 in accounts payable to vendors for invoices received from these companies but not yet paid. John P. Laborde has no interest in these companies.

The law firm of Gordon, Arata, McCollam, Duplantis and Eagan, of which B.J. Duplantis, one of our directors, is a Senior Partner, provided legal services for us during 2002 and 2001. The value of these services totaled approximately $14 and $20 during 2002 and 2001, respectively.

NOTE 9 — HEDGING ACTIVITIES:

We enter into hedging transactions to secure a price for a portion of future production that is acceptable at the time at which the transaction is entered. The primary objective of these activities is to reduce our exposure to the possibility of declining oil and gas prices during the term of the hedge. These hedges are designated as cash flow hedges when entered into. We do not enter into hedging transactions for trading purposes. Monthly settlements of these contracts are reflected in revenue from oil and gas production. Under generally accepted accounting principles, beginning January 1, 2001, in order to consider these futures contracts as hedges, (i) we must designate the futures contract as a hedge of future production and (ii) the contract must be effective at reducing our exposure to the risk of changes in prices. Changes in the market values of futures contracts treated as hedges are not recognized in income until the hedged item is also recognized in income. If the above criteria are not met, we will record the market value of the contract at the end of each month and recognize a related increase or decrease in derivative expenses (income). Any amount received or paid to terminate a contract reduces the asset or liability, respectively, associated with the contract. Changes in market value previously recognized in other comprehensive income are amortized to earnings over the remaining life of the original contract.

We adopted SFAS No. 133 effective January 1, 2001. Upon adoption of SFAS No. 133, as amended, the after-tax increase in fair value over historical cost of our oil put contracts of $1,736 was a transition adjustment that was recorded as a gain in equity through other comprehensive income.

At December 31, 2003, our open gas puts were reflected as assets at a fair value of $1,040. Our gas put contracts are with Bank of America, N.A., Bank of Montreal and Bank One. Put contracts are purchased at a rate per unit of hedged production that fluctuates with the commodity futures market. The historical cost of the put contracts represents our maximum cash exposure. We are not obligated to make any further payments under the put contracts regardless of future commodity price fluctuations. Under put contracts, monthly payments are made to us if NYMEX prices fall below the agreed upon floor price, while allowing us to fully participate in commodity prices above that floor. Our put contracts are considered effective hedges under SFAS No. 133 and all changes in fair value are recorded, net of taxes, in other comprehensive income.

In addition to put contracts, we utilized fixed-price swaps to hedge a portion of our future gas production. Our swap contracts are with Bank of America. Swaps typically provide for monthly payments by us if prices rise above the swap price or to us if prices fall below the swap price. At December 31, 2003, our swap contracts were considered effective hedges and reflected as liabilities at fair value of $12,106.

At December 31, 2003, we had an accumulated other comprehensive loss of $8,763, net of tax, of which $7,869 related to our gas swap contracts and the remainder related to our gas put contracts.

In October 2002, we reached an agreement with Enron North America Corp. to purchase the portion of our fixed price natural gas swap contract settling subsequent to October 2002 for $5,917. We amortized $3,632 of derivative expenses during 2003 related to previously recorded other comprehensive loss from the swap contract.

Because over 90% of our production has historically been derived from the Gulf Coast Basin, we believe that fluctuations in NYMEX prices will closely match changes in the market prices we receive for our production. Oil contracts typically settle using the average of the daily closing prices for a calendar month. Natural gas contracts typically settle using the average closing prices for near month NYMEX futures contracts for the three days prior to the settlement date.

The following table shows our hedging positions as of January 1, 2004:

	Natural Gas Puts		
	Daily Volume (MMBtus/d)	Floor	Unamortized Cost
2004	90,000	$3.50	$2,416

	Fixed-Price Gas Swap	
	Daily Volume (MMBtus/d)	Price
2004	15,000	$3.42
2005	15,000	3.42

In January 2004, we entered into a put contract with J. Aron & Company (a subsidiary of Goldman Sachs) that effectively hedges 7,500 barrels of oil per day of Gulf Coast Basin production at a put price of $25.00 from February 2004 through December 2004. The cost of the contract totaled $1,683, which will be charged to earnings as the contract settles. This oil put contract is not reflected on the balance sheet as of December 31, 2003.

During 2003, 2002 and 2001, we recognized $8,711, $15,968 and $2,604, respectively, of derivative expenses. The components of derivative expenses were as follows:

	Year Ended December 31,		
	2003	2002	2001
Cost of put contracts settled	$5,079	$13,175	$3,112
Change in fair value of ineffective swap	-	104	(339)
Amortization of other comprehensive loss for ineffective swap	3,632	2,689	(169)
Total derivative expense	$8,711	$15,968	$2,604

For the years ended December 31, 2003, 2002 and 2001, we realized net increases (decreases) in oil and gas revenue related to hedging transactions of ($1,576), $5,953 and ($1,819), respectively.

NOTE 10 — COMMON STOCK:

On February 1, 2001, our stockholders approved a proposal to amend our certificate of incorporation, in connection with the Basin merger, increasing the number of authorized shares of our common stock from 25,000,000 to 100,000,000.

NOTE 11 — COMMITMENTS AND CONTINGENCIES:

On July 29, 2002, we entered into a $28,000 work commitment for at least five wells over a two-year period on the Pinedale Anticline in the Green River Basin in Wyoming. After the initial $28,000 investment and the drilling of five wells, we will have earned a 50% working interest in the project area. As of December 31, 2003, we had fulfilled the obligation under the original work commitment.

We lease office facilities in New Orleans, Louisiana, and two locations in Denver, Colorado and Houston, Texas under the terms of long-term, non-cancelable leases expiring on various dates through 2006. We also lease automobiles under the terms of non-cancelable leases expiring at various dates through 2006. The minimum net annual commitments under all leases, subleases and contracts noted above at December 31, 2003 were as follows:

2004	$954
2005	613
2006	134
2007	-
2008	-
Thereafter	-

NOTE 11 — COMMITMENTS AND CONTINGENCIES: (Continued)

Payments related to our lease obligations for the years ended December 31, 2003, 2002 and 2001 were approximately $1,140, $889 and $1,280, respectively. We sublease office space to third parties, and for the years ended 2003, 2002 and 2001, we recorded related receipts of $816, $239 and $285, respectively. A minimum lease rental to be received from the sublease of office space is $609 and $71 for each of the years ended December 31, 2004 and 2005, respectively.

We are contingently liable to surety insurance companies in the aggregate amount of $40,966 relative to bonds issued on our behalf to the United States Department of the Interior Minerals Management Service (MMS), federal and state agencies and certain third parties from which we purchased oil and gas working interests. The bonds represent guarantees by the surety insurance companies that we will operate in accordance with applicable rules and regulations and perform certain plugging and abandonment obligations as specified by applicable working interest purchase and sale agreements.

As previously reported, Goodrich Petroleum Corporation, Goodrich Petroleum Company, L.L.C. and Goodrich Petroleum Company-Lafitte, L.L.C. filed civil action number 2000-06437, in Harris County, Texas, against Stone Energy Corporation, seeking seismic data at Lafitte Field and unspecified damages. On October 29, 2003, after a trial of this matter, the jury awarded Goodrich Petroleum Company-Lafitte, L.L.C. damages in the amount of $538, which has been accrued in other expense. As of March 1, 2004, a judgment had not yet been entered by the court. There has been no indication whether the plaintiff will appeal this decision. We are evaluating whether an appeal will be filed by Stone.

We are also named as a defendant in certain lawsuits and are a party to certain regulatory proceedings arising in the ordinary course of business. We do not expect these matters, individually or in the aggregate, will have a material adverse effect on our financial condition.

OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. Under OPA and a final rule adopted by the MMS in August 1998, responsible parties of covered offshore facilities that have a worst case oil spill of more than 1,000 barrels must demonstrate financial responsibility in amounts ranging from at least $10,000 in specified state waters to at least $35,000 in OCS waters, with higher amounts of up to $150,000 in certain limited circumstances where the MMS believes such a level is justified by the risks posed by the operations, or if the worst case oil-spill discharge volume possible at the facility may exceed the applicable threshold volumes specified under the MMS's final rule. We do not anticipate that we will experience any difficulty in continuing to satisfy the MMS's requirements for demonstrating financial responsibility under OPA and the MMS's regulations.

NOTE 12 — EMPLOYEE BENEFIT PLANS:

We have entered into deferred compensation and disability agreements with certain of our officers whereby we have purchased split-dollar life insurance policies to provide certain retirement and death benefits for certain of our officers and death benefits payable to us. The aggregate death benefit of the policies was $3,185 at December 31, 2003, of which $1,901 was payable to certain officers or their beneficiaries and $1,284 was payable to us. Total cash surrender value of the policies, net of related surrender charges at December 31, 2003, was approximately $1,015 and is record in other long-term assets. Additionally, the benefits under the deferred compensation agreements vest after certain periods of employment, and at December 31, 2003, the liability for such vested benefits was approximately $800 and is recorded in other long-term liabilities.

We have adopted a series of incentive compensation plans designed to align the interests of our directors and employees with those of our stockholders. The following is a brief description of each of the plans:

i. The Annual Incentive Compensation Plan provided for an annual cash incentive bonus that ties incentives to the annual return on our common stock, to a comparison of the price performance of our common stock to the average quarterly returns on the shares of stock of a peer group of companies with which we compete and to the growth in our net earnings per share, net cash flows and net asset value. Incentive bonuses are awarded to participants based upon individual performance factors. Stone incurred expenses of $851 and $523, net of amounts capitalized, for the years ended December 31, 2002 and 2001, respectively, related to incentive compensation bonuses paid under this plan. This plan was terminated upon the approval and adoption of the Revised Plan, discussed below.

In February 2003, our board of directors approved and adopted the Revised Annual Incentive Compensation Plan. The revised plan provides for annual cash incentive bonuses that are tied to the annual return on our common stock, to a stock performance comparison to our peers, to growth in our earnings and net asset value per share and to the achievement of certain strategic objectives as defined by our board of directors on an annual basis. Stone incurred expense of $2,636, net of amounts capitalized, for the year ended December 31, 2003 related to incentive compensation bonuses to be paid under the revised plan.

ii. The 2001 Amended and Restated Stock Option Plan provides for 4,225,000 shares of common stock to be reserved for issuance pursuant to this plan. At the 2003 Annual Meeting of Stockholders, the stockholders approved, through proxy voting, an amendment to the Plan that increased the aggregate number of shares of Common Stock reserved for issuance by 1,000,000 shares. Under this plan, we may grant both incentive stock options qualifying under Section 422 of the Internal Revenue Code and options that are not qualified as incentive stock options to all employees and directors. All such options must have an exercise price of not less than the fair market value of the common stock on the date of grant and may not be re-priced without stockholder approval. Stock options to all employees vest ratably over a five-year service-vesting period and expire ten years subsequent to award. Stock options issued to non-employee directors vest ratably over a three-year service-vesting period and expire five years subsequent to award. The number of shares reserved for issuance pursuant to the 2001 Amended and Restated Stock Option Plan does not include approximately 348,000 outstanding stock options assumed on February 1, 2001 in connection with the merger with Basin Exploration, Inc.

iii. The Stone Energy 401(k) Profit Sharing Plan provides eligible employees with the option to defer receipt of a portion of their compensation and we may, at our discretion, match a portion or all of the employee's deferral. The amounts held under the plan are invested in various investment funds maintained by a third party in accordance with the directions of each employee. An employee is 20% vested in matching contributions (if any) for each year of service and is fully vested upon five years of service. For the years ended December 31, 2003, 2002 and 2001, Stone contributed $677, $645 and $688, respectively, to the plan.

A summary of 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. Exer. Price	Number of Options	Wgtd. Avg. Exer. Price	Number of Options	Wgtd. Avg. Exer. Price
Outstanding at beginning of year	2,419,557	$37.68	2,058,531	$38.04	1,880,077	$34.39
Granted	571,600	36.63	625,500	34.23	588,200	48.72
Exercised	(127,600)	21.20	(160,582)	24.55	(245,885)	28.81
Forfeited	(127,998)	44.42	(103,892)	44.35	(163,861)	47.18
Expired	-	-	-	-	-	-
Outstanding at end of year	2,735,559	$37.92	2,419,557	$37.68	2,058,531	$38.04
Options exercisable at year-end	1,292,239	36.39	1,082,536	32.77	963,761	27.95
Options available for future grant	902,000		353,550		910,750	
Weighted average fair value of options granted during the year	$16.57		$16.12		$23.86	

The weighted average 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) dividend yield of 0%, (b) expected volatility of 41.89%, 45.10% and 44.24% in the years 2003, 2002 and 2001, respectively, (c) risk-free interest rate of 3.66%, 3.11% and 4.88% in the years 2003, 2002 and 2001, respectively, and (d) expected life of six years for employee options and four years for director options.

NOTE 12 — EMPLOYEE BENEFIT PLANS: (Continued)

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

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	**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**
$9 – $20	90,200	1.6 years	$12.26	90,200	$12.26
20 – 30	391,000	3.3 years	23.76	387,000	23.71
30 – 40	1,536,935	8.4 years	35.52	405,385	35.64
40 – 50	161,000	6.8 years	44.49	88,136	45.17
50 – 70	556,424	6.0 years	56.73	321,518	56.95
	2,735,559	6.9 years	37.92	1,292,239	36.39

NOTE 13 — OIL AND GAS RESERVE INFORMATION – UNAUDITED:

Our 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 market value of the oil and gas properties or the cost that would be incurred to obtain equivalent reserves.

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

	Oil in MBbls	Natural Gas in MMcf
Proved reserves as of December 31, 2000	33,625	398,524
Revisions of previous estimates	(1,703)	(2,876)
Extensions, discoveries and other additions	2,727	52,742
Purchase of producing properties	24,765	59,849
Production (1)	(4,023)	(65,570)
Proved reserves as of December 31, 2001	55,391	442,669
Revisions of previous estimates	905	2,378
Extensions, discoveries and other additions	2,101	59,785
Purchase of producing properties	188	240
Sale of reserves	(329)	(726)
Production (1)	(6,237)	(65,694)
Proved reserves as of December 31, 2002	52,019	438,652
Revisions of previous estimates	317	(12,233)
Extensions, discoveries and other additions	8,893	86,821
Purchase of producing properties	3,731	10,647
Sale of reserves	(71)	(28)
Production	(5,727)	(62,536)
Proved reserves as of December 31, 2003	59,162	461,323
Proved developed reserves:		
as of December 31, 2001	43,094	351,269
as of December 31, 2002	39,772	334,692
as of December 31, 2003	45,128	339,664

(1) Excludes gas production volumes related to the volumetric production payment.

The following tables 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, including a reduction for estimated plugging and abandonment costs that are also reflected as a liability on the balance sheet at December 31, 2003 in accordance with SFAS No. 143. You should not assume that the future net cash flows or the discounted future net cash flows, referred to in the table below, represent the fair value of our estimated oil and gas reserves. As required by the SEC, we determine estimated future net cash flows using period-end market prices for oil and gas without considering hedge contracts in place at the end of the period. The average 2003 year-end product prices for all of our properties were $31.79 per barrel of oil and $6.30 per Mcf of gas. Future production and development costs are based on current costs with no escalations. Estimated future cash flows net of future income taxes have been discounted to their present values based on a 10% annual discount rate.

NOTE 13 — OIL AND GAS RESERVE INFORMATION – UNAUDITED: (Continued)

	Standardized Measure Year Ended December 31,		
	2003	2002	2001
Future cash inflows	$4,788,471	$3,713,318	$2,274,665
Future production costs	(682,970)	(581,539)	(481,874)
Future development costs	(472,193)	(414,518)	(285,568)
Future income taxes	(969,394)	(645,160)	(212,883)
Future net cash flows	2,663,914	2,072,101	1,294,340
10% annual discount	(867,991)	(697,391)	(385,764)
Standardized measure of discounted future net cash flows	$1,795,923	$1,374,710	$908,576

	Changes in Standardized Measure Year Ended December 31,		
	2003	2002	2001
Standardized measure at beginning of year	$1,374,710	$908,576	$1,982,749
Sales and transfers of oil and gas produced, net of production costs	(429,544)	(289,830)	(333,200)
Changes in price, net of future production costs	380,812	862,253	(2,097,695)
Extensions and discoveries, net of future production and development costs	505,213	240,056	134,876
Changes in estimated future development costs, net of development costs incurred during the period	11,477	(43,607)	61,994
Revisions of quantity estimates	(59,663)	22,146	(19,982)
Accretion of discount	178,476	103,880	294,179
Net change in income taxes	(174,286)	(279,829)	828,820
Purchases of reserves in-place	104,957	3,374	314,394
Sales of reserves in-place	(622)	(1,403)	-
Changes in production rates due to timing and other	(95,607)	(150,906)	(257,559)
Net increase (decrease) in standardized measure	421,213	466,134	(1,074,173)
Standardized measure at end of year	$1,795,923	$1,374,710	$908,576

NOTE 14 — SUMMARIZED QUARTERLY FINANCIAL INFORMATION – UNAUDITED:

	Quarter Ended			
	March 31,	June 30,	Sept. 30,	Dec. 31,
	(amounts in thousands, except per share amounts)			
2003				
Revenue	$157,546	$117,212	$115,993	$117,554
Income from operations	88,901	48,512	44,289	44,488
Income before cumulative effects of accounting changes	54,633	28,627	22,767	27,218
Net income	55,858	28,627	22,767	27,218
Earnings common per share:				
Income before cumulative effects of accounting changes	$2.07	$1.09	$0.86	$1.03
Cumulative effects of accounting changes	0.05	-	-	-
Basic	$2.12	$1.09	$0.86	$1.03
Income before cumulative effects of accounting changes	$2.06	$1.08	$0.86	$1.02
Cumulative effects of accounting changes	0.05	-	-	-
Diluted	$2.11	$1.08	$0.86	$1.02
2002				
Revenue	$80,530	$100,438	$94,523	$102,004
Income from operations	14,200	29,982	26,231	34,599
Net income	6,256	15,984	13,693	19,466
Earnings common per share:				
Basic	$0.24	$0.61	$0.52	$0.74
Diluted	0.24	0.60	0.52	0.74

GLOSSARY OF CERTAIN INDUSTRY TERMS

The definitions set forth below shall apply to the indicated terms as used in this Form 10-K. All volumes of natural gas referred to herein are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit and in most instances are rounded to the nearest major multiple.

Active property. An oil and gas property with existing production.

BBtu. One billion Btus.

Bcf. One billion cubic feet of gas.

Bcfe. One billion cubic feet of gas equivalent. Determined using the ratio of one barrel of crude oil to six mcf of natural gas.

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

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Debt-to-Book Capital Ratio. A ratio indicating the financial leverage of a firm, which is calculated by dividing long-term debt by the sum of long-term debt and stockholders' equity.

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

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

Finding costs. Costs associated with acquiring and developing proved oil and gas reserves which are capitalized pursuant to generally accepted accounting principles, excluding any capitalized general and administrative expenses.

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

LIBOR. Represents the London Inter-Bank Overnight Rate of interest.

Liquidity. The ability to obtain cash quickly either through the conversion of assets or the incurrence of liabilities.

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

Mcf. One thousand cubic feet of gas.

Mcfe. One thousand cubic feet of gas equivalent. Determined using the ratio of one barrel of crude oil to six mcf of natural gas.

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

MMBtu. One million Btus.

MMcf. One million cubic feet of gas.

MMcfe. One million cubic feet of gas equivalent. Determined using the ratio of one barrel of crude oil to six mcf of natural gas.

MMcfe/d. One million cubic feet of gas equivalent per day.

GLOSSARY OF CERTAIN INDUSTRY TERMS: (Continued)

Make-Whole Amount. The greater of 104.125% of the principal amount of the 8¼% Notes and the sum of the present values of the remaining scheduled payments of principal and interest discounted to the date of redemption on a semiannual basis at the applicable treasury rate plus 50 basis points.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells.

Net profits interest. An interest in an oil and gas property entitling the owner to a share of oil or gas production subject to production costs.

Overriding royalty interest. An interest in an oil and gas property entitling the owner to a share of oil or gas production free of production and capital costs.

Pooling-of-Interests. An accounting method for business combinations in which the financial statements and results of operations are prepared as if the companies had been combined at the beginning of the earliest period shown. In addition, the assets and liabilities of the combining companies are carried forward to the combined entity at book value.

Present value. When used with respect to oil and gas reserves, present value means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date of the report or estimate, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%.

Primary term lease. An oil and gas property with no existing production, in which Stone has a specific time frame to establish production without losing the rights to explore the property.

Production payment. An obligation of the purchaser of a property to pay a specified portion of future gross revenues, less related production taxes and transportation costs, to the seller of the property.

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 exceeds production expenses and taxes.

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 which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

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

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 oil and gas regardless whether such acreage contains proved reserves.

Volumetric production payment. An obligation of the purchaser of a property to deliver a specific volume of production, free and clear of all costs, to the seller of the property.

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

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Annual Meeting
The Company's Annual Meeting of Stockholders will be held at 10:00 a.m. on May 20, 2004, in the Denechaud Room of the Le Pavillion Hotel, New Orleans, Louisiana.

Form 10-K
Copies of the Company's Annual Report on Form 10-K filed with the Securities and Exchange Commission may be obtained upon request to Investor Relations or through the Company's website at www.StoneEnergy.com. Quarterly reports and press release information also may be accessed through the website.

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