IN GOOD COMPANY

PIONEER NATURAL RESOURCES 2003 ANNUAL REPORT

2003: A RECORD YEAR

2003 ACCOMPLISHMENTS

- REPORTED RECORD NET INCOME OF $411 MILLION, OR $3.46 PER DILUTED SHARE.
- REPORTED RECORD CASH FLOW FROM OPERATIONS OF $764 MILLION.
- REDUCED DEBT $113 MILLION.
- POSTED 26% RETURN ON EQUITY AND 15% RETURN ON CAPITAL EMPLOYED.
- INCREASED PRODUCTION 36%.
- REPLACED 193% OF PRODUCTION WITH AVERAGE FINDING AND DEVELOPMENT COST OF $6.64 PER BOE.
- DRILLED 383 WELLS WITH 84% SUCCESS.
- DRILLED NEW DISCOVERIES IN THE GULF OF MEXICO, ALASKA, ARGENTINA AND TUNISIA.

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FORWARD-LOOKING STATEMENTS

Except for historical information contained herein, the statements in this document are forward-looking statements that are made pursuant to the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995. Forward-looking statements and the business prospects of Pioneer Natural Resources Company are subject to a number of risks and uncertainties that may cause Pioneer's actual results in future periods to differ materially from the forward-looking statements. These risks and uncertainties are described on pages 4 and 8 through 12 of Pioneer's Form 10-K included with this report.

DEFINITIONS

BOE: Barrel oil equivalent
MBOE: Thousand barrels oil equivalent
MCFE: Thousand cubic feet gas equivalent
TCFE: Trillion cubic feet gas equivalent

IN GOOD COMPANY

RARELY, THE RIGHT ELEMENTS COME TOGETHER TO CREATE A UNIQUE ENVIRONMENT, PROVIDING EXCEPTIONAL STRENGTH.....

IN GOOD COMPANY

TO OUR SHAREHOLDERS

FELLOW SHAREHOLDERS:
In 2003, we reported record earnings and cash flow, increased our oil and gas production 36%, posted strong drill bit results and reduced debt. Over the last three years, we have added significant net asset value; and our stock price performance, reserve replacement and finding cost results were in the top quartile of our peer group. We are at one of the strongest points in our history.

In the midst of declining production in the U.S. oil and gas industry, we grew our U.S. production 44%. At a time when other oil and gas exploration and production companies are turning to acquisitions as the primary means of offsetting declines in their base production, we are growing organically, through drill bit success.

Look beyond the numbers, and you will see that our strength is founded on the stability of our legacy assets, supported by a solid financial position, distinguished by our exploration track record and quality opportunities and driven by the talented, committed people of Pioneer. I've asked a few of our people to share their views with you, and through the remainder of this report, you'll read firsthand what being a part of Pioneer is all about.

ON A FIRM FOUNDATION
A solid foundation is key to the long-term success of any company. Long-lived production from our onshore assets and high-volume production from new offshore fields form a great base. Danny Kellum, our executive vice president of domestic operations, shares with you his views on our U.S. producing assets, and Güimar Vaca Coca, president of our Argentina subsidiary, will discuss our assets and opportunities there. We've also included information on our properties in Canada, South Africa and Tunisia.

Danny and his team have done an excellent job of maintaining production from our onshore base by reinvesting only a portion of the cash flow and diligently controlling costs. They have a multiyear inventory of onshore drilling locations to support continued activity. In the deepwater Gulf of Mexico, we had three fields producing at year end, added another field in January and plan to have three more fields producing by mid-year. With three other offshore fields in the commercialization phase and an active exploration program, we expect that Danny and his team will be busy for quite a while.

In Argentina, Güimar and his team have successfully navigated the challenges of an unstable economic and political environment, and with the environment now stabilizing, they are back on track with production growth in 2003 and expectations for a record year in 2004. Our oil drilling program has benefited from lower drilling and operating costs offering excellent returns, and we're encouraged by stronger gas demand and the outlook for improving Argentine gas prices.

WITH FINANCIAL STRENGTH
Through 2002, the majority of our cash flow was committed to the development of our successful exploration projects. These projects are now becoming cash generators, at a time of strong oil and gas prices, and delivering exceptional returns. We are committed to applying part of the returns to further strengthen the balance sheet and have made significant progress in this regard, as evidenced by our recent upgrade to Investment Grade status. By the end of 2004, we expect to have reduced our ratio of debt to book capital to within our targeted range. Tim Dove, our chief financial officer, reviews our financial results. He discusses the priority we place on maintaining the financial flexibility to develop future successes while funding our typical capital budget and our other options for using cash flow to benefit our shareholders.

AND QUALITY OPPORTUNITIES
A great base and sufficient capital are crucial and can generate moderate near-term growth, but quality opportunities are what drive exceptional long-term results. Our opportunity pipeline is filled with projects in various phases of commercialization beginning with recent discoveries being evaluated for development and progressing to fields in the last months of development before production. Our prospects range from lower-risk satellite or offset opportunities near existing facilities to rank exploration ideas in proven basins.

Bill Hannes, vice president of engineering and development, outlines the discoveries that are currently in final development and commercialization phases. With responsibility for projects from discovery to first production, his team is critical to our success. The Falcon field was our first operated deepwater development, and it and a satellite discovery we also operate were brought to first production ahead of schedule, setting new records for deepwater development.

Our exploration team is led by Chris Cheatwood, executive vice president of worldwide exploration. With a track record of success in the deepwater Gulf of Mexico, South Africa, Gabon, North Africa and most recently in Alaska, the exploration team's contribution to Pioneer's current strength is evident. Chris discusses the drivers behind Pioneer's successful program and the opportunities Pioneer will be testing in the years to come.

While the primary growth driver for Pioneer has been exploration, we've completed over half of a billion dollars in acquisitions since 2000. These acquisitions have supplemented our ownership in key areas and projects, assets we know best, adding significant value. Over the next five years, we will build on this program and are expanding our acquisition team. Ray Alameddine, executive vice president of worldwide business development, reviews our strategy and our progress on advancing acquisitions to achieve a more balanced approach to growth.

ABOUT EMPOWERED PEOPLE

The strength I'm most proud of is less evident and more difficult to quantify but is at the heart of our success. It's our culture. I am confident in our ability to extend Pioneer's success, and my confidence is based in large part on our unique culture and the enthusiasm, commitment and talent of our people. We continually challenge ourselves to be innovative, to accept individual responsibility for the common good and empower people to make a difference. We believe in being authentic, direct and open. We take the health and safety of our employees and the environment seriously. We like to win, but only if we can do it with integrity. When we achieve individual and Company performance goals, all employees participate in our restricted stock program, aligning their interests with those of our shareholders. Our culture is best understood through the words and faces of our people, and on the pages that follow, you'll hear from many of them directly.

IN GOOD COMPANY

This year marks my 25th year with this Company, and while we believe our strengths are unique, we're not content. We'll work hard to add to our base asset foundation, further solidify our financial flexibility, add new quality opportunities to the pipeline and advance our successful culture.

We're never fully satisfied with our accomplishments as each day brings new challenges and opportunities. We're up for the task.

Scott D. Sheffield

SCOTT D. SHEFFIELD
Chairman, President and CEO

ABOUT EMPOWERED PEOPLE

"It's awesome to work for a company whose management is on your side. I have been given the technical responsibility combined with the creative freedom to work outside the box–promoting a sense of loyalty, a sense of impact to the bottom line, and an honest desire to ensure that Pioneer achieves its growth targets around the world."

Bill Gray, Engineering Technical Specialist

Todd Abbott
Ken Abdulah
Chris Acosta
Joe Acosta
Ryan Ainsworth
A. R. Alameddine
Kathy Alderson
Dale Alexander
Eduardo Alimonda
Hashim Alkhersan
Rex Allen
Tamera Allen
Benito Almodova
Dawn Altman
Jimmy Alvarez
Marina Alvarez de Toledo
Orlando Alvenda
Bevan Alwin
Sam Amador
Abel Amato
Jenna Anaya
Connie Anderson
Howard Anderson
Terry Anderson
Jori Andrade
Enrique Aramburu
Joe Archuleta
Dee Dee Arnold
Miguel Arriola
David Askew
Francklin Assoko-Mvé
Jamie Asuncion
Alberto Atienza
Stuart Atnipp
Dana Atwater
Andy Ausbrooks
Denny Ausbrooks
Steve Aust
Yohannes Ayalew
Melinda Baeza
Clyde Bailey
Gaines Bailey
Jim Bailey
Debbie Baker
Gary Baker
Ray Baker
Teresa Baker
José Balastegui
Paula Balch
Jake Balderrama
Lynn Bangs
Dale Bankhead
Larry Barclay
Danny Barker
Don Barker
Margie Barlow
Mary Barnes
Pam Barnhart
Judy Barr
Larry Barr
Shawna Barrett
Miguel Barrientes
Gervasio Barzola
Garry Batla
Leslie Bauer
Frank Bayus
Lalania Beago
Shannon Becker
Catherine Bedwell
Melinda Beggs
Ward Belanger
Tracey Bell
Justin Bellamy
Miguel Bellani
Brett Benardino
Mark Bengtson
Carolyn Benson
Marni Benson
Jeannette Benton
Wade Bergen
Phil Berger
Mike Berta
Guy Bertrand
Doris Biddy
Longin Biemer
Billy Bishop
Doug Bishop
Kathy Bishop
Howard Blanchard
Sergio Blint
Kari Boen
Charles Bolf
John Boone
Randy Borchardt
Eduardo Bosio
Liz Bosselle
Cindi Boyd
Rodney Boyd
Dave Braddock
Dwayne Braden
Michael Bradford
Jorge Braga
Caroline Braich
Paula Brandt
Alejandra Bravo
Butch Brazell
Stephen Brewster
Barbara Bright
Rebecca Brisenio
Carlos Brocco
Wesley Brock
Don Bromley
Jayne Bromley
Craig Brooks
Larry Brooks
Brenda Brown
Pride Brown
Bonnie Browning
Don Bryson
Mary Bryson
Dave Buckell
Erika Budic
Denny Bullard
Dan Bulot
Charles Buras
Eddie Burgess
Kimberly Burke
Barry Burns
Tom Burns
Don Burris
Bobby Burritt
Betty Bush
Diane Bustamante
Scott Buxman
Ed Caamano
Tish Caamano
Nelson Cabrera
Mike Camara
Marcelo Camiscia
Joel Campbell
Bill Cantrell
Pat Cantu
Nélson Cardenas
David Carey
Jeffrey Cariker
Lynne Carlson
John Carmen
Pat Carne
James Carr
Bob Carroll
Randy Carruth
James Caruthers
Steven Casanova
Mike Casey
Matthew Cashion
Jenny Castaneda
Biolanda Castillo
Paul Castles
Charles Castro
Vanessa Castro
Genaro Catano
Adam Cerecero
Martín Cevallos
Randy Chambers
Greg Champion
Diana Chapman
Wayne Charpentier
Bill Chase
Gerard Chauvin
Chris Cheatwood
Ray Chenard
Shi-Chen Cheng
Clarence Cheramie
Ron Chernuka
Bryan Chesser
Patricia Chi
Andrea Chiappe
Michael Chisholm
Wei-Chun Chu
Claudio Churraín
Daniel Cinquemani
Bob Clark
Jeff Clark
Jennifer Clark
Jon Clark
Joy Clark
Karen Clark
Ronnie Clayton
Carrie Clymer
Robert Cobb
Chad Coffindaffer
Caren Colborn
Fred Cole
Vickie Coles
Jody Conaway
Dan Condley
David Coney
Juan Contreras
Myron Cook
Robert Cook
Stacy Cook
Rusty Cooper
Trish Copeland
David Corbett
Jim Cornwell
Chris Coronado
John Coss
Ted Cottrell
Bert Courrege
Johnny Cox
Rick Croft
Steve Cruth
Maria Cueva
Ronald Cunningham
James Cunningham
Judy Curb
Sam Curry
Fábian D'Andrea
Allynson Dale
Alejandra Dapelo
Kirby Dark
Noel Dastugue
Eugene Dauterive
Todd Davidson
Michael Davidson
J. Gayle Davis
Judy Davis
Mike Davis
T.J. Davis
Will Davis
Christopher Daws
Ron DeBault
Rich Dealy
Larry Deatherage
Lonnie Decker
Michael Degeyter
Claudio Deimundo
Hugo Del Prete
Levi DeLeon
Christina DeRouen
Clark Deviveaux
Darlene Devenny
Wally Dexter
Wade DeYoe
Carlos Di Paolo
Jorge Diaz
Héctor Díaz
Jeff Diedrich
Gustavo Díez
Todd Dillabough
Marc Dingler
Carol Anne Doherty
Anne Dollar
Anita Domínguez
Carlos Domínguez
Ken Dominiec
Kim Doud
Bobby Douget
Beverly Dougherty
Sharon Dougherty
Linda Dove
Tim Dove
Wilbur Dover
Andrea Downey
Mark Drew
Connie Dula
Lisa Duley
Michael Dunkel
Mike Dunn
Joanne Dye
Tony Earnest
Colin Edgar
Gary Edge
Charles Edmiaston
Dan Edwards
Donna Edwards
Don Egli
Mo El-Hitamy
Louis Elliott
Tom Elser
Heather Elwood
Franky Embery
Jeff Emmert
Rebecca Endell
Carlos Escudero
Lee Eslick
Nelda Evans
Richard Evans
Susan Evans
John Eveleigh
Hugo Facchini
Teresa Fairbrook
Sylvie Fardy
Gerry Faske
Jeff Faw
Paul Fawks
Nancy Ferrada
Daniel Ferreiro
Zachary Ferris

"We are always striving to improve — we set goals, accomplish them and move on. We don't stand still and we sure don't go back."

Caren Colborn, Lease Operator

"Our management has done a remarkable job of moving the workforce from the simple *team* concept to one of pride in the fact that we're a member of this progressive Pioneer *family*."

Brett Benardino, Director, Purchasing

"Pioneer culture is all about its people. Pioneer employees have strong professional skills, respect for their fellow employees and a humble spirit."

Rich Dealy, Vice President and Chief Accounting Officer

"Every day is different and an interesting challenge. I can count on each group to do their part and do it well."

Carol Tessier, Director, Enterprise Solutions

Janie Fields
Laura Fina
Bryan Findley
Lynne Fink
Charles Fish
Mike Flowers
Joe Flud
Pat Foley
Greg Folger
Lynne Foote
Francis Forbes
Bobby Foret
Carolyn Foster
John Francois
Enrique Frankenfeld
Jim Franklin
Susan French
John Fretwell
Harvey Friesen
Ronald Fruge'
Eric Fry
Jennifer Fry
Oscar Furlan
Jerry Fuselier
Ariel Galarza
Patrick Gallegos
Henry Galpin
Garrett Gandy
Carlos Garcia
JoAnn Garcia
Raul Garcia
Jorge García Laszúk
Norberto Garcia Madeo
Rick Garland
Scott Garrick
Darrel Garrison
Albert Garza
Joel Garza
Charles Gates
Terry Gaudet
Sonalee Gaur
Surita Geldenhuys
Lisa Gele'
David George
Harold George
Gene Gerber
Bruce Gerrard
Alejandro Giaquinta
Mark Giesaking

Gary Gilbert
Aaron Gilbreath
Linda Gilbreath
Roger Gilcrease
Greg Gill
Bob Gill
Sam Giovinco
Cal Girouard
Rita Gitzel
Robert Glass
Jack Glidewell
Jack Glover
Byron Goertzen
Izabella Goldberg
Rickey Golden
Louis Goldstein
Brandi Goldston
Randy Golson
Norma Gómez de Torres
Geronimo Gonzales
Jorge Gonzalez
José Gonzalez
Beverly Goode
Greg Gower
Marty Graham
Charles Graves
Bill Gray
Joseph Gray
Les Greenlee
Frosty Grice
Luis Grzona
Troy Guidry
Rosie Gutierrez
George Haas
Steve Haddock
Alan Hadfield
Tom Hagen
Tom Halbouty
Chris Halfmann
Frank Hall
Gene Hall
Joey Hall
Larry Hambek
Ricky Hammontree
Ed Hance
Bill Hannes
Jerry Hardin
David Harrell

John Harris
Randy Harris
Katherine Hartig
Donna Hartman
Tom Harwedel
Len Haseloff
Matthew Hatfield
Biff Hatfield
Joseph Hayden
Curtis Haynes
Pam Hays
Vance Hazzard
Mandy Hedgpeth
Terry Henderson
Larry Hendrix
David Heneghan
Mario Henrique
Hubert Hensley
Bryan Henson
Larry Herman
Adolfo Hernandez
Angie Hernandez
Daniel Hernandez
Freddy Hernandez
Joe Hernandez
Mario Hernandez
Sam Hicks
David Higgins
Bud Hill
Craig Hill
Robert Hillger
Darrell Hilliard
Mike Hinson
Kati Hitchens
Tommy Hodge
Troy Hoefer
Charlie Hoff
Yvonne Hoff
Les Hogan
Abel Hogeda
Ryan Holcomb
Robert Holley
Toni Holliman
Rocky Holly
Dave Holmes
Andy Hooker
James Hooks
Steve Horner
Dale Houska

Billy Houston
Bill Howard
James Howard
Sue Howard
Rod Huckabee
Francine Hudgens
Rick Hue
Blane Huff
Danny Huffman
Bill Hughes
Robert Hull
Don Hunter
Terry Hunter
Kathy Ingram
Milt Ingram
Jennifer Isbell
Tommy Jackson
Tracie Jackson
Michael Jacobs
Krystyna Jagielko
Jeff James
Kim Janzen
Carlos Jara
Linda Jaworski
Shan Jennings
Daryl Jensen
Terry Jensen
Tom Jensen
Armando Jimenez
Jami Jinarajan
Tim Johns
Steve Johnson
Berry Johnson
Tom Johnston
Robbie Jones
Ben Jones
Benjamín Jordá
Dee Jordan
Edwin Joseph
Jay Joseph
Kevin Jurgajtis
Greg Kaiser
Kenny Kapp
Cindy Kasper
Karyn Kasprzak
Ken Kasza
David Keller
Larry Kelley
Linda Kelly

Danny Kellum
Dee Ann Key
Pam Kienle
Doug Kimbrell
Carolyn King
Pat Kinsinger
Beth Klunder
Bill Knight
Craig Knutson
Daniel Kokogián
Kenneth Kreitz
Craig Kuiper
Lisa Kunkel
Rodney Kunze
Monica Laabs
Phil Lacasse
Mariana Laight
Scott Lakey
Rodney Lamberson
Norris Lane
Morris Langevin
James Langley
Isaac Larkin
Pierce Larned
Melony Larsen
Lorris Lathrop
Melvin Latiolais
Miguel Lavia
Jason Lavigne
Gustavo Laville
Daphne June Leaner
Paul Leavitt
Malcolm Ledet
John Lee
Paul Lee
Charles Lefebvre
Lee Lehtonen
Susan Leigh
David Lejeune
John Lelek
Ronald Leleux
Mike Lempa
Guy Leonard
Paul Leonard
Raymond Lerma
Janice Lewis
John Lewis
Shane Lewis
Tim Lewis

Miguel Liendo
Jerry Lindop
Chris Lipari
Dennis Lithgow
Stanley Little
Rodney Littleton
Tag Locklar
Heath Loftin
Jerry Loftis
Glenn Logsdon
Eduardo Lopepe
Sergio López
Agustín López Herrero
Carmen Lorincz
Daniel Lorlovick
Ken Lorlovick
Chad Lowell
Ivonne Lozano Mejía
Bob Lucas
Pete Luna
Pat Lyles
Cheryl Lyon
Hal Macartney
Walter Maddox
Alejandro Madotta
Mike Mahan
Judy Makowsky
Melissa Maldanado
Ramesh Malepati
Steve Mamerow
Mike Mantzke
Gildardo Manzano
Juan Manzano
Gary Marchand
Norma Marchuk
José Mardonez
Mechelle Markham
Jose Marquez
Kay Martin
Kim Martin
Marvin Martin
Sheila Martin
Jorge Martinez
Jesse Mathews
Paul Mathews
Bobby Maxie
Ben May
Davis May
Terri May

Lonnie Mayers
Randy Maytum
J K McBee
Carl McBryde
David McCain
Cole McClendon
Jeff McCown
Erin McCuistion
Sharon McDaniel
Paul McDonald
John McEachern
Bill McElya
Curtis McEntire
Sharon McGee
Tom McGhie
Denton McNew
Michelle McWilliams
Toby Medina
Alex Medrano
Christopher Medrano
James Meier
Juan Mendez
Hugo Mendía
Rosie Mendoza
César Mera
Mary Mesh
Alan Messimer
Kelly Mihecoby
Jim Miller
Mike Miller
Keith Mills
Brad Miner
Bryan Mitchell
Morris Mitchell
Stacy Mitchell
Jerry Mixon
Floyd Mobray
Phillip Molina
Jose Monjes
Gene Monson
Jorge Monteleone
Julie Montgomery
Nélson Montivero
Brad Moore
Erica Moore
Terre Moore
Lyndal Moreno
Cory Morgan
Aldo Moro

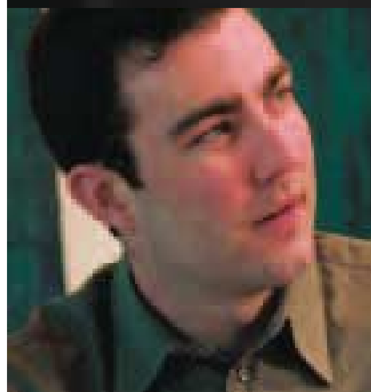
"The people at Pioneer allow you to think independently but offer a vast experience base, fostering personal growth. Pioneer's accessible and supportive culture has quickly helped me transition from a college graduate to a contributing member of the Pioneer team."

Erin McCuistion, Reservoir Engineer

Eddie Morris
Elisha Morris
Brad Morrison
Mary Morton
Pat Morton
Barbara Mueller
David Murphy
Terry Murphy
Carl Murray
Colin Murray
Vernon Murray
Vincent Murray
Stephen Nail
Walter Narambuena
Nabil Nashed
Kathy Navarrete

Karen Oremus
Juan Ortegon
Gary Osborn
Keith Overby
Steve Owen
Dana Owens
Gervais Owono Akoué
Jan Pace
Gleno Packer
Steve Pagan
Joe Paredes
Glen Paris
David Parker
Travis Parker
Wes Parker
Steven Parr

Juan Poblete
Deborah Pollock
Héctor Pommier
Bobby Pool
Billy Portie
Tommy Powell
Chris Powers
Roger Powers
Paul Prather
Javier Presutti
Tom Prichard
John Pry
Mike Puga
Andrew Quarles
Daniel Quiroga
John Ragan



Anthony Navarrette
Henriette Ndjoteme-Nendjot
Buddie Neatherlin
Marlene Neff
David Nelson
Dennis Nelson
Laura Net
Heather Neustaedter
Carolyn New
Ray Newsom
Allyn Newton
Les Niemi
Josh Nichols
Tim Nightengale
Gilbert Nino
Thurman Noland
Noel Nolet
Rod Nordyke
Doris Norton
Mark Nuckels
Eduardo Ocampo
Orlando Ochoa
Dusty Ochs
Terry Ochs
Randy Offenberger
Maximiliano Oficialdegui
Donavon Olivier
Dustin Olivier
Renny Olivier
Vernon Orange

David Parton
Oscar Pasache
Bob Patton
Chris Paulsen
Larry Paulsen
Elton Pax
Marilynn Payne
JoAnne Pears
Ronald Peltier
Teri Pender
Deana Pennington
Elias Perez
José Pérez
Bob Perry
Jeff Perry
Ben Persinger
Bob Persson
Jason Peter
Louis Peters
Michelle Peterson
Sandy Petty
Steve Petty
David Phillips
Dena Phillips
Chung Pi
Keith Pickett
Roy Pierre
Jeff Pilcher
Idalia Pina
Mary Pirtle
Michael Pitts

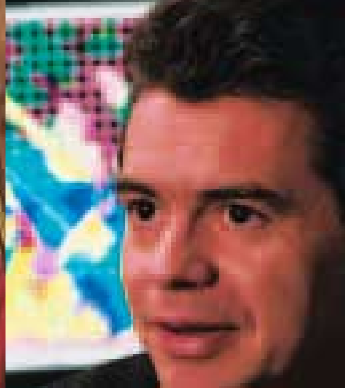
Sean Ragan
Rick Raindl
Cindy Rainsford
Oscar Ramirez
Stephen Ramos
Sherri Randal
Marek Ranoszek
Jimmy Rasor
Rusty Rauscher
Roger Reams
Lisa Reed
Tim Reed
Bill Reed
Mike Reel
Robby Reeves
Pat Reich
Carl Reist
Gary Reppart
Julio Retamal
Ronald Retzloff
Carlos Reyes
David Reyes
Domingo Reyes
Nora Ribera
Reba Ricks
Billy Rider
Gary Roberts
Ken Roberts
Doug Robins
Chris Robinson
Artie Rodriguez

"For me, the key to our culture is trust. Senior management sets the course and empowers people to get the job done."

Steve Mamerow, Manager, Worldwide Drilling

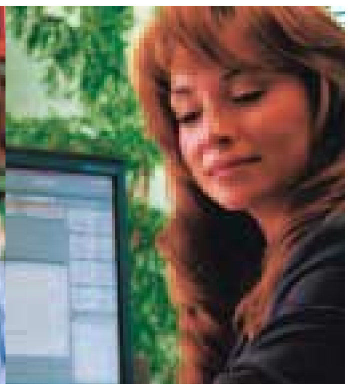
"Pioneer's culture is about community, cooperation and camaraderie – from the top down. There's a feeling that what we do for the Company matters, that we can all positively contribute to the bottom line, and our efforts are appreciated by both management and our co-workers alike. We all work hard to achieve great results, and we have fun doing it."

Diane Bustamante, Reservoir Engineering Advisor



"Even with the huge growth in our company in the past couple of years, no one is ever too busy to stop and make you feel like a priority."

Dawn Altman, Engineering Technician



"I felt Pioneer's positive culture the minute I walked in the door. Pioneer truly treats its employees as its greatest asset."

Caroline Braich, Attorney

Richard Rodriguez
Ricardo Rodríguez
Faye Rogers
Gaylon Rogers
John Rogers
Herslee Rogers
Ronnie Romero
José Ronchino
Shawn Roose
Daniel Rosato
Carl Rounding
Ken Russell
Subrina Russell
Darren Russett
Guillermo Russo
Dave Ryan
Celina Sainz de Peña
Herminio Sanchez
Sam Sanchez
David Sanders
Milton Sanders
Robert Sands
Scott Sapaugh
Greg Satterfield
Diane Sauriol
Gregg Schell
Kevin Schepel
Mario Schiuma
Kevin Schmidt
Carlos Schneider
Larry Schneider
Lois Scoggins
Analía Scordo
Dave Scott
Don Scott
Kerry Scott
Len Scott
Roy Scott
Shane Seals
Jim Seery, Jr.
Dennis Sensat
Ceferino Sepulveda
Patsy Settle
Danny Seymour
Johnny Shaddix
Charles Sharp
Wayne Shaw
Ken Sheffield
Scott Sheffield
Tom Sheffield
Del Shelton
Rodney Shepherd
Jim Sherrard
Timothy Sherwood
Linda Shields
Jerry Shirley
Ricky Shuck
Larry Shugart
Chris Siebert
Lori Siemens
Eduardo Silva
Ken Silver
Dave Simpson
Joey Sims
Wayne Sims
Dennis Singer
Eric Singer
Charlie Sizemore
Marc Skeen
Alan Smith
Barbara Smith
Chrissy Smith
Elton Smith
Galen Smith

Jackie Smith
James Smith
Kay Smith
Mark Smith
Sherri Smith
Valorie Smith
Will Smith
Tim Sneed
Aubrey Soileau
Harold Sorey
Luis Soto
Shannon Soudelier
Pablo Soule Canau
Tom Spalding
Joe Spencer
Mike Spiser
Donny Spivey
Kevin Spratlen
Susan Spratlen
Jerry Spring
Jenna Staggs
Bruce Stanley
Shalleen Stanley
Sherene Starr
Ira Stein
Thomas Steinwinder
Andy Stephens
Bob Stepp
James Stevens
Carolyn Stevenson
David Stewart
Deb Stewart
Kerrie Stewart
Jacques St-Hilaire
Jay Still
Russ Stoker
George Stokes
Genna Storz
Roderick Strambler
Dean Straw
Donny Strickland
Dave Strickler
Craig Sturtevant
Allan Sullins
Kevin Swafford
Norman Swango
Randy Talbot
Becky Tarrh
Jim Tate
Bobby Taylor
Guillermo Terrazas
Charles Terry
Carol Tessier
Paul Tessmer
Marcos Thibaud
Dave Thomas
Duane Thomas
Jessica Thomas

Kenya Thomas
T.J. Thomas
Zie Thomas, Sr.
Bonnie Thompson
Darrell Thompson
Dan Thorsen
Mike Tibbets
Jean Tillery
Mark Timmons
Steve Timmons
Federico Tiscornia
Cameron Todd
Lance Todd
Kenneth Tolbert
Sandy Traughber
Alberto Travieso
Paul Treadwell
Jeffery Tshikhudo
Kelly Tull
Bill Tulp
Julie Turbyfill
Harry Turner
Jim Uhelski
Eli Urbanczyk
Güimar Vaca Coca
Ann Vandiver
David Vandiver
April Vann
Jorge Vasquez
Viola Vasquez
Sandy Vela
Eugenio Velazco
Leopoldo Venditti
Eduardo Verdugo
Steve Vest
Eugenia Viejobueno
Vanina Vignolo
Gabe Villalobos
Shadin Vincent
Austin von der Hoya
Bryan Waddell
Shane Wade
Michelle Wagner
Lowell Waite
Jimmy Walbaum
Chris Walker
Jeff Wallace
Ricky Wallace
Zane Wallace
Laura Walsh
Judy Walters
Tommy Warr
Robert Warwas
Nadine Watkins
John Watson
Kimberly Watson
Levert Weaver
Paul Weaver

Wendel Webster
Albert Wegelin
Paul Welch
Bradley Wells
Kay Werner
Charles Whaley
James Whatley
Larry Wheeler
Cindy Whiddon
Dennis White
Jim White
Linda White
Tom White
William White
Jim Whitehead
Robert Whitehead
Lindy Whitehurst
Kelly Whitley
Jimmy Whitney
Mark Wickwar
Jaret Wieler
Monica Wightman
Rhonda Wilk
Kory Willey
Bonetia Williams
Dan Williams
Dean Williams
Diana Williams
Jerry Williams
Michelle Williams
R.B. Williams
Brian Wilson
Mickey Wilson
Sharon Wilson
Jonas Wingfield
David Winkowski
Jimmy Winn
Kathleen Winter
Jason Wiseman
Mark Withrow
Carrie Wittkopf
Hershal Wolfe
Kevin Woller
Derek Wood
Stewart Wood
Toby Wood
Jana Worley
Jerry Worobeck
Tracy Wright
Qingming Yang
Dyann Yarbrough
Rudy Ybarra
Tommy Yeager
Francis Young
Kevin Young
Dale Yount
Bruce Zerr
Pablo Zubiaurre

"It's great to work for a company where you look forward to Monday as much as Friday. This is a company where the executives know their employees on a first-name basis and are familiar with their projects. Not only does the Company allow you to express your ideas, it also acts on them."

Louis Goldstein, Manager, US Onshore Exploitation

CORPORATE OFFICERS:

(IN ORDER FROM LEFT TO RIGHT, TOP TO BOTTOM)

Scott D. Sheffield
Chairman, President
and Chief Executive Officer

Danny L. Kellum
Executive Vice President,
Domestic Operations

Timothy L. Dove
Executive Vice President
and Chief Financial Officer

Chris J. Cheatwood
Executive Vice President,
Worldwide Exploration

Mark L. Withrow
Executive Vice President,
General Counsel and Secretary

A. R. Alameddine
Executive Vice President,
Worldwide Business Development

Susan A. Spratlen
Vice President,
Investor Relations and Communication

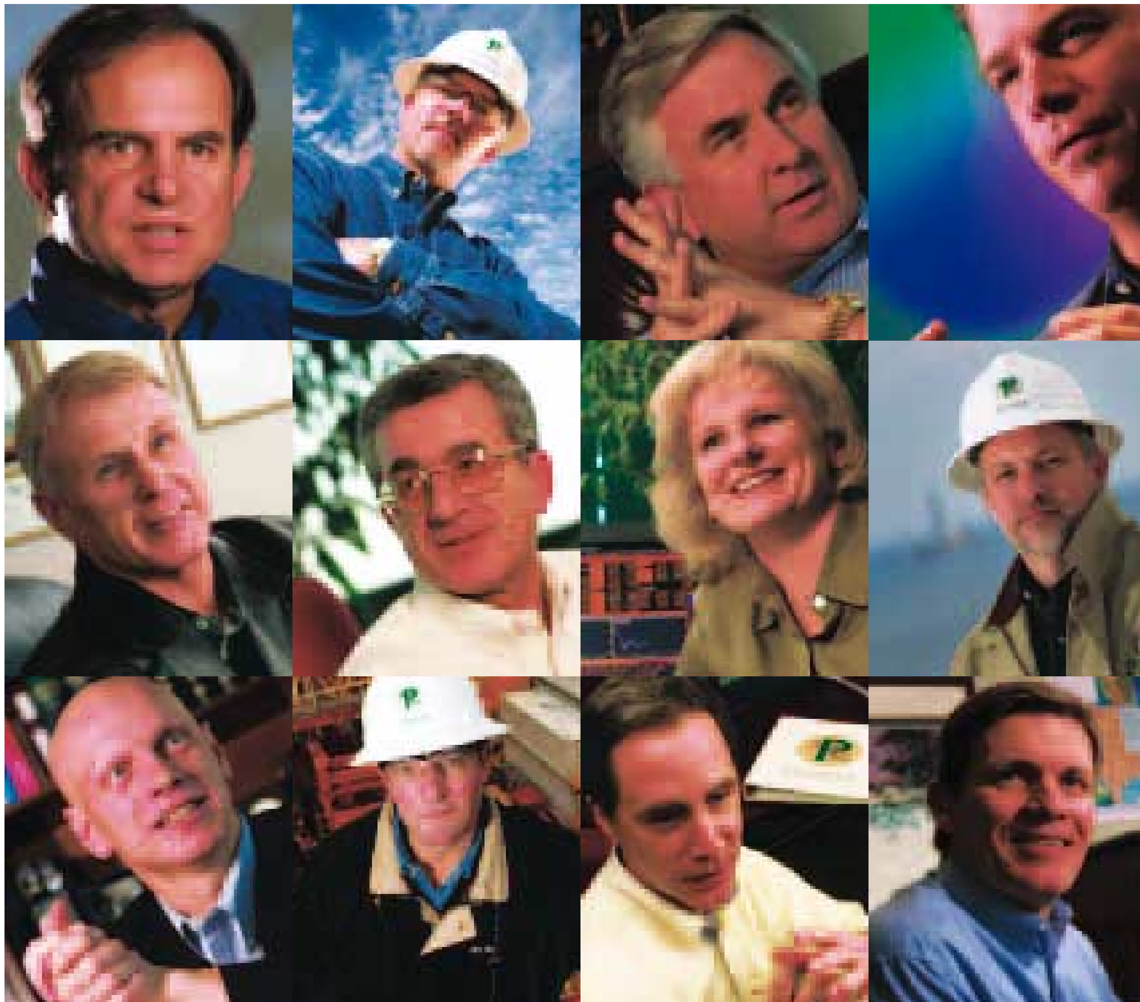
William F. Hannes
Vice President,
Engineering and Development

Richard P. Dealy
Vice President and Chief Accounting Officer

Jay P. Still
Vice President,
Gulf of Mexico Operations

Thomas C. Halbouty
Vice President and Chief Information Officer

Larry N. Paulsen
Vice President,
Administration and Risk Management



"Pioneer people are given the tools they need and the encouragement to take creative risks. Scott and the management committee promote team values and have the patience to stay the course."

Tom Spalding, Gulf Coast Exploration Manager

"Last year, I was called to active duty in support of the global war on terrorism. The Company immediately assured me that they would support me and my family, freeing me to concentrate on my wartime responsibilities overseas and service to the nation. It's this corporate spirit of taking care of its people that makes me proud to be here at Pioneer."

Greg Champion,
Director of Negotiations, Business Development

ON A FIRM FOUNDATION

"I am proud of the role that our domestic legacy assets have played as we've transformed Pioneer into a global company."

Technology has been one of the keys to significant operating cost reductions. In the Spraberry field, we have significantly reduced costs by employing the largest SCADA (System Control Analytical Data Acquisition) system in the world. This system allows us to remotely monitor field operations, maximizing the reach of our lease operators and minimizing downtime.

We have put a lot of effort into building a strong position in the Spraberry, a long-lived oil field in West Texas, becoming the largest operator in the field. When we formed Pioneer in 1997 and added long-lived gas in the Hugoton and West Panhandle fields, we knew we were creating a new company with a great foundation, and I am proud of the role that our domestic legacy assets have played as we've transformed Pioneer into a global company.

We use a small portion of the cash flow from these assets to maintain their production, about $150 million per year. During 2003, our onshore U.S. assets generated cash flow of about $530 million. The excess cash flow from these assets has fueled the transformation of Pioneer, providing the capital for our exploration program and for developing the new fields we discovered in the Gulf of Mexico and South Africa. And these legacy fields will be there long into the future providing fuel for our growth.

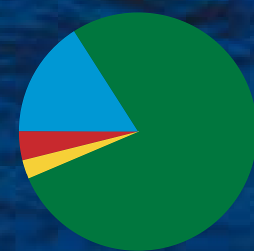
Today, our onshore U.S. assets are still about 70% of our total company reserves and offer slow production declines with an average reserve to production ratio of 20 years, and an average productive life of 30 years. Still, we stay busy drilling new development wells in these fields to maintain and in some cases increase production, and since we have a lot of drilling locations in inventory, we'll be active in these areas for several more years.

We operate nearly all our wells in these fields and own the gathering and processing facilities associated with most of our production. As a large operator in each of

DANNY KELLUM
Executive Vice President, Domestic Operations



PROVED RESERVES*
4.7 TCFE/789 MMBOE



UNITED STATES	79%
ARGENTINA	16%
AFRICA	3%
CANADA	2%

% PROVED DEVELOPED	65%
PV_{10} VALUE OF RESERVES	$6.0 BILLION
RESERVES/ PRODUCTION RATIO	14 YEARS
2003 AVERAGE FINDING COST	$1.11 PER MCFE OR $6.64 PER BOE
3 YEAR AVERAGE FINDING COST	$1.13 PER MCFE OR $6.76 PER BOE
2003 RESERVE PLACEMENT	193%
3 YEAR AVERAGE RESERVE PLACEMENT	216%

* Major property reserves (89% of value) were audited by independent petroleum engineers.

these fields, we are relentless about capturing the economies of scale and managing our costs. We believe in our people, we encourage their input, and they come through for us time and time again.

We continually challenge ourselves to find opportunities to squeeze more profit out of these fields, and encourage and train our lease operators to think like engineers. We are relentless in seeking ways to drill cheaper, better and faster. In fact, we have reduced drilling costs in the Spraberry field to the point that we have a contract with a major oil company that also operates in the field to drill their wells for them, earning a fee and interest in their production.

Technology has played a huge role in reducing costs by automating many of our processes and allowing us to remotely monitor our wells. Our technology group is pioneering and innovative, and we've seen big savings as a result.

This year, we plan to drill about 240 wells in these onshore fields. We're excited about the opportunity we see to continue to extend the success we've seen from our drilling program in the Pawnee field area in South Texas. We're also testing the potential of some acreage we hold in northern Louisiana. While the onshore assets may not be as glamorous as our new deepwater fields, they are at the heart of our success and will be for many years to come.

That's not to say that we're not excited about our new deepwater fields. By the end of 2004, we expect that 35% of Pioneer's production will come from just 21 wells in

OTHER INTERNATIONAL

Pioneer's North American gas production base includes several operated fields in Canada where the Company expects moderate drill bit growth. While Pioneer's strategy has been to build on this position through acquisitions, opportunities to buy Canadian assets and meet minimum return hurdles have been very limited.

Oil production from the Sable field offshore South Africa was initiated in 2003 utilizing a floating production, storage and offloading vessel.

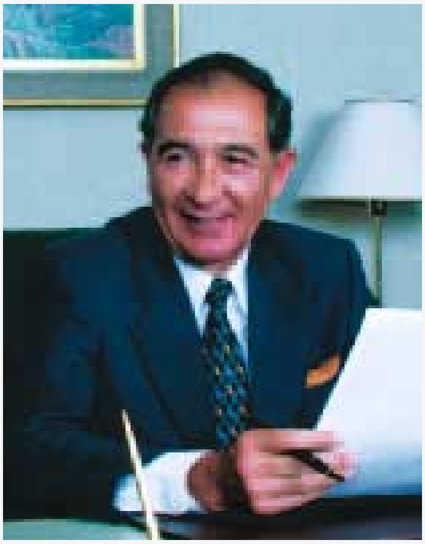
Pioneer's latest international entry is in northern Africa where the Company has built a large acreage position in Tunisia. The exploration program there is still in its early stages, but three wells are already producing oil, two discoveries are being evaluated, and additional wells are planned this year.

three distinct projects. The Canyon Express gas project set a record for the world's deepest production when it began producing in September 2002. We are the sole owner and operator of the Falcon gas system and initiated production there in March 2003 with the Falcon field. We have since added production to the system from the Harrier satellite field and expect to add production from two more satellites later this year. We plan to initiate production from our third project, the spar development of the Devils Tower oil and gas field, by mid-year.

To date, our production rates from deepwater fields have been higher than expected, and we've had good uptime on the facilities. Infrastructure is king in the deepwater, lowering the reserve threshold and reducing lead time for nearby discoveries. For example, our Falcon development team set an industry record achieving first production from the Harrier satellite field in less than 12 months. We are working with the development team on plans to tie in two satellite fields at Devils Tower, and the exploration team has several additional satellite prospects to drill.

Our deepwater operations team is focused on maximizing the value of these high-return deepwater fields by carefully controlling costs and minimizing downtime. The deepwater Gulf of Mexico is a demanding technical and business environment, and through these projects we've gained critical expertise that we hope to leverage into other deepwater opportunities in the Gulf and around the world.

— DANNY KELLUM



GÜIMAR VACA COCA, President of Pioneer Natural Resources (Argentina) S.A.

ARGENTINA

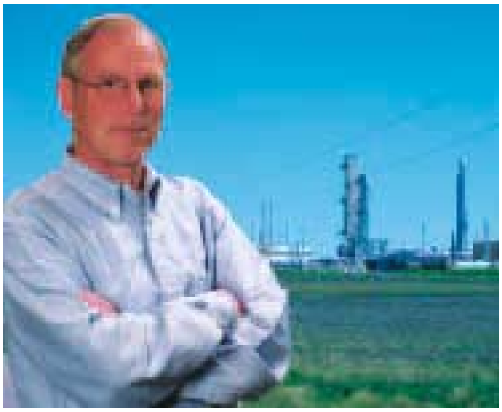
As Argentina's economic and political crisis engulfed the country in 2002, we stood strong with assets of excellent quality. Our people responded by working harder to weather the crisis and protect our business, seizing opportunities to improve long-term results. We enhanced the value of the peso-denominated gas stream by recovering liquids that can be sold in dollar-denominated markets. We shut down our gas drilling efforts, but shot new 3-D surveys and worked to advance our exploration program while costs were low. We gained a more favorable position for marketing gas and acquired additional acreage. Oil development continued, benefiting from reduced operating costs for peso-denominated services with dollar-denominated revenues.

Today, the environment is stabilizing, our oil drilling continues to deliver high-return growth, our gas sales have strengthened, and we are again developing gas reserves with good economics where we can strip out liquids. We expect that the government will soon implement a program for gradual gas price increases, further improving gas development economics. When the market for gas expands, we are in position to significantly increase production through development of our existing discoveries and new exploration.

For 2004, we are back on track for meaningful growth in both oil and gas sales and have doubled our capital budget, which is still within expected Argentine cash flow. Most of the budget is directed to lower-risk development drilling and facilities. We are eager to appraise significant gas discoveries and continue our exploration drilling program. Our resilience was tested, and the storm has subsided. The Argentina team has emerged even stronger.

— GÜIMAR VACA COCA

BILL HANNES, Vice President, Engineering and Development



HENRY GALPIN, Vice President of Gas Processing

RESPONSIBLE OPERATIONS

Pioneer joined the Environmental Protection Agency's Natural Gas STAR program as a charter member in the gas processing sector in 2000. As a result of our program for reducing methane emissions, Pioneer was recognized as the EPA's Gas STAR Rookie of the Year in 2001 and was named Processing Partner of the Year in 2002.

We operate two gas processing facilities, the Fain plant in the Texas panhandle and the Satanta plant in western Kansas, and have several other smaller gas treating plants. Reducing methane emissions has always been a priority, but joining the STAR program has created a more formal platform for our environmental protection policies, and provides resources to help us identify additional emissions reduction opportunities.

Our entire team, from the front-line staff operating our facilities to senior management, is committed to protecting the environment and to good corporate citizenship. It's an ongoing process, and our participation in the EPA's STAR program highlights our efforts.

— HENRY GALPIN

COMMERCIALIZATION AND DEVELOPMENT

To bring large-scale projects from discovery to first production, we needed a strong team with broad experience and expertise. These are the kind of people who are in high-demand and can go anywhere because they are the best at what they do. So what attracts them to Pioneer? Their compensation is a given. We must pay them well, but they can get that anywhere. It's our culture that's different. We take top talent and provide them the opportunity to use their skills, putting them on world-class projects that rival the majors'. We challenge them, give them the tools they need, hold them accountable and let them do what they do best. We all work hard and enjoy what we do.

We work to build good working relationships with our partners and service contractors to make us all one team with common goals. We do our share and more, even on projects that we don't operate. We welcome the opportunity to work with and learn from other companies known for their expertise. We participate in decisions, contribute solid solutions and aren't afraid to ask questions.

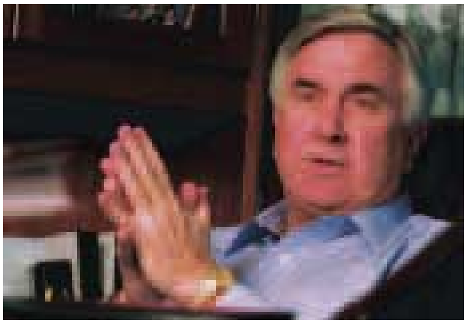
We currently have nine discoveries in various stages of commercialization. In the deepwater Gulf of Mexico, first production is targeted by mid-year from the Devils Tower, Raptor and Tomahawk fields, and we're planning tie-backs for three other fields.

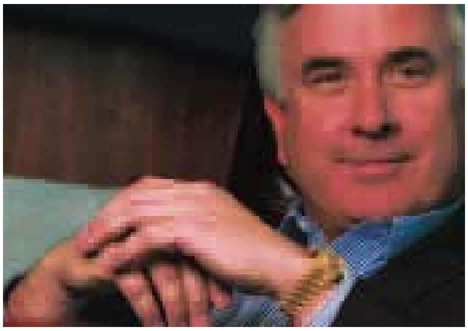
In Gabon, we are awaiting results from our current drilling campaign to finalize the plan for development. We drilled three successful wells in Alaska during 2003, have farmed into additional acreage and are evaluating the potential to develop our Oooguruk field. Offshore South Africa, we are encouraged with the potential to develop gas reserves on our blocks. We are working to establish a contract to supply gas to an existing synthetic gasoline plant just onshore from our blocks.

The Falcon gas system was our first operated project in the deepwater Gulf, and we're proud to have brought the first two wells there on line ahead of schedule. We have a number of interesting projects on the table and are committed to maximizing their value.

– BILL HANNES

WITH FINANCIAL STRENGTH





TIM DOVE, Executive Vice President and Chief Financial Officer

"We'll preserve our financial flexibility and prudently steward the investments made by our fellow stakeholders."

We are well on the way to achieving our financial goals. We have gone through the paces of launching an exploration program, having early success, and then facing the challenge of funding multiple large-scale development projects at a time when cash was scarce. It was because of the quality and stability of our legacy assets that we were able to divert development dollars to these new high-impact projects, maintain our exploration program and reduce debt while still maintaining our base production.

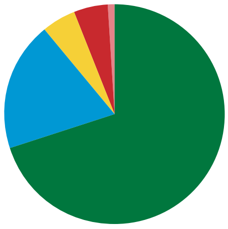
Yes, we have been the beneficiary of relatively high commodity prices during this period, just like everyone in our industry. But to accomplish this task, we have stuck to our plan and fulfilled past promises. This has taken patience, a focus on prudent capital allocation and dedication to continuous balance sheet improvement. Our efforts have been rewarded with a return to Investment Grade status.

Today, we have substantial flexibility and firepower. Our debt statistics have shown consistent improvement. Our ratio of debt to total book capitalization was below 47% at the end of the year, and we expect to reach our targeted range of 37% to 43% during the next few quarters. A total of 26 of the world's largest financial institutions participated in the renewal of our $700 million corporate credit facility at the end of 2003, and we announced the initiation of a dividend for 2004, reflecting our growing strength and confidence in our financial future.

Pioneer has many advantages. We have legacy long-lived onshore assets that continue to generate significant excess cash flow, especially at today's commodity prices. The strong cash flow from the Canyon Express and Falcon area gas projects will soon be augmented by cash flow from the Devils Tower project. These deepwater projects are some of the highest rate of return projects in the Company. Their impact on our financial results

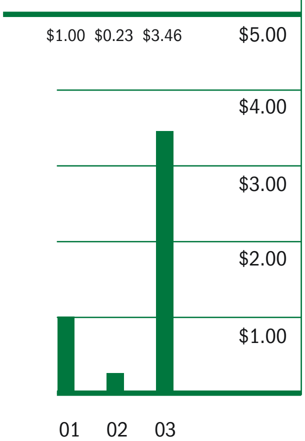
The audit committee of the board regularly meets with Pioneer's management. Pictured (left to right) are board member Harty Gardner, retired treasurer of Mobil, Rich Dealy, chief accounting officer, board member Jim Houghton, a retired senior tax partner with Ernst & Young, and Tim Dove, chief financial officer.

2004 CAPEX BUDGET
$550-$600 MILLION

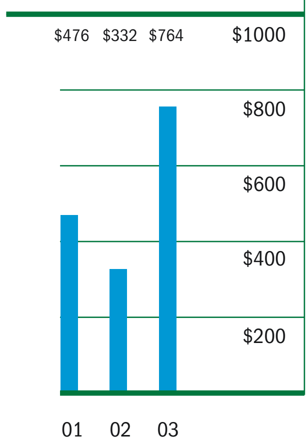


UNITED STATES	70%
ARGENTINA	19%
AFRICA	5%
CANADA	5%
OTHER FOREIGN	1%

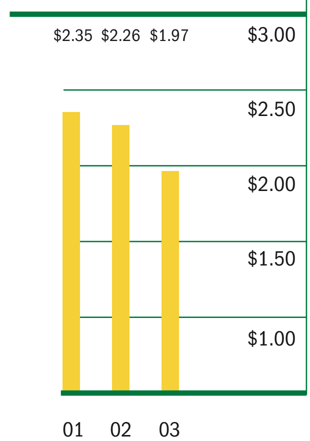
EARNINGS PER SHARE (DILUTED)



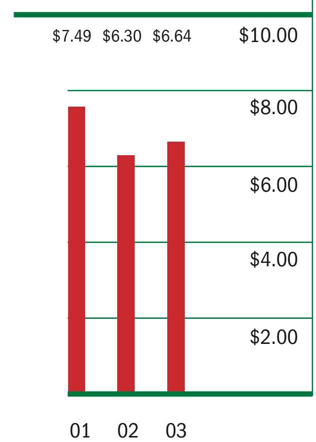
NET CASH PROVIDED BY OPERATING ACTIVITIES IN MILLIONS



YEAR-END DEBT PER BOE OF PROVED RESERVES



AVERAGE FINDING COST PER BOE



was dramatic in 2003: we generated record net income of $411 million, a return on equity of 26% and a return on capital employed of 15%.

Oil and gas production for 2003 was up 36% over the prior year, and cash flow from operations more than doubled to $764 million. As we bring on four more deep-water fields, we expect our production will significantly increase again this year, by 15% to 25% before the impact of potential acquisitions. We expect to generate annual cash flows that are several hundred million dollars above our normal capital needs for the next few years.

We take seriously our responsibility to invest this cash flow to achieve the best returns. We've set the initial budget for our 2004 capital program at $550 million to $600 million and would look to increase the budget to appraise or begin developing a discovery or for potential acquisitions. We have a substantial inventory of projects, and because our best returns have come from investing in good projects, we will retain the financial wherewithal to develop the discoveries that have already been made and to continue to explore for and develop new reserves. We have a strong track record in acquiring properties as well, having bought over a half billion dollars worth of properties in the last five years, all in our core areas. We've been buying more of what we already own and know, and have added significant value.

Although we have a large number of high-quality projects to invest in over the next several years, we also believe in returning capital to our shareholders. The recently announced $200 million share repurchase program and the dividend are steps in that direction. Finally, we expect to reduce debt a minimum of $100 million this year as we continue to progress toward our leverage targets.

Our outstanding finance team has been instrumental in our success, and they will continue to play an integral role in Pioneer's future. Our fast-paced culture demands a sharp team, with the knowledge and resourcefulness to handle an ever-changing environment, and they consistently deliver.

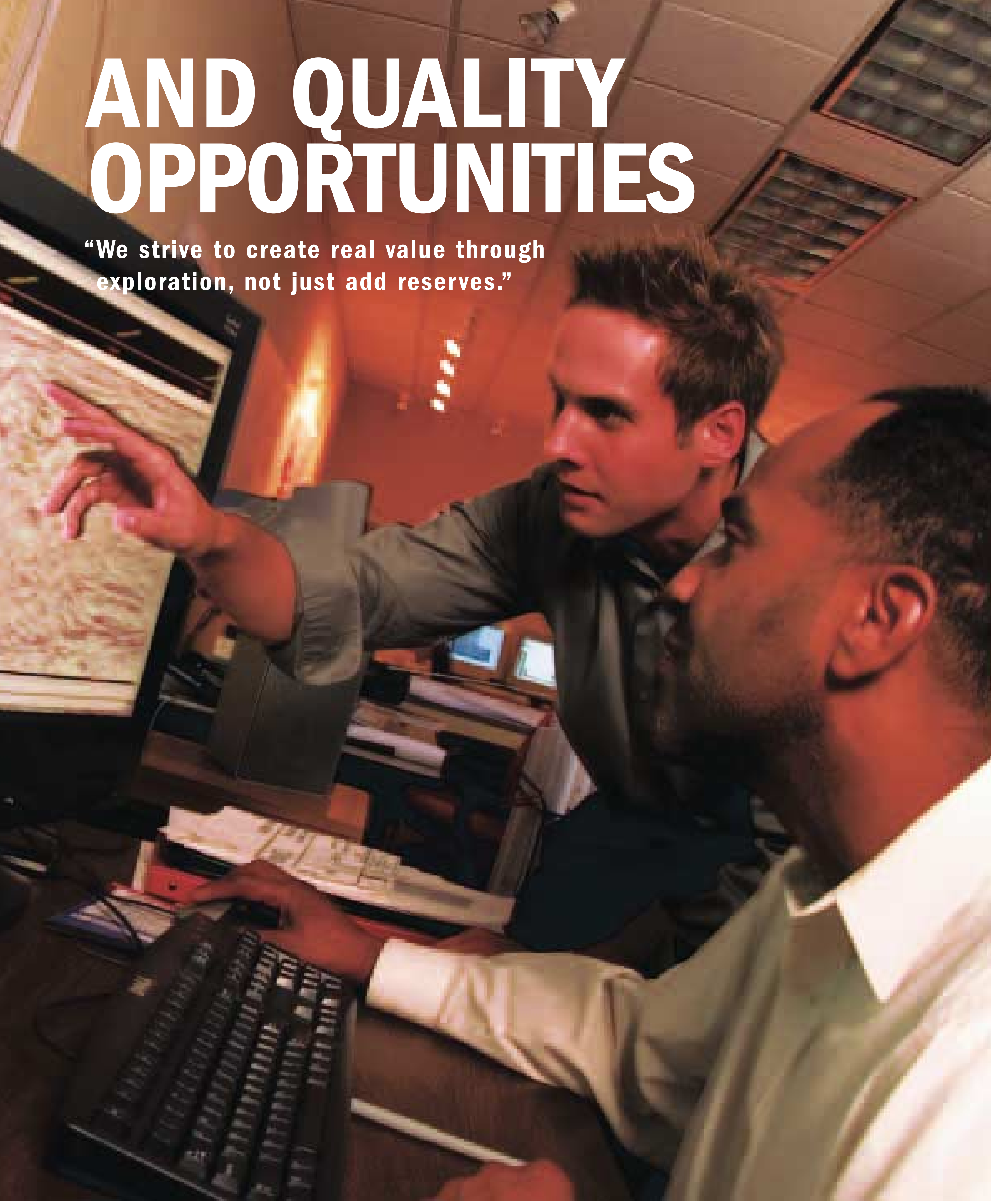
We maintain an open, close working relationship with the audit committee of our Board of Directors and are fortunate to have such great depth of industry knowledge and experience on the committee.

Our team's focus will be on financing our plan as it is implemented, properly assessing risks and returns, actively practicing portfolio management, ensuring that our projects meet strict economic thresholds and accurately evaluating capital allocation decisions. We'll be patient, value-oriented and thinking long-term. We'll preserve our financial flexibility and prudently steward the investments made by our fellow stakeholders.

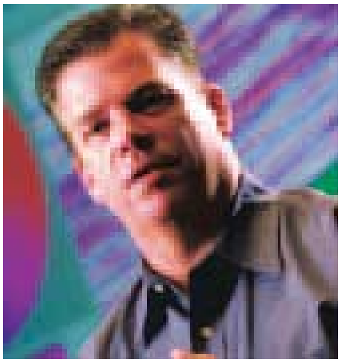
— TIM DOVE

AND QUALITY OPPORTUNITIES

"We strive to create real value through exploration, not just add reserves."



CHRIS CHEATWOOD, Executive Vice President, Worldwide Exploration



When Pioneer was formed in 1997, a key component of the company's vision was creating a successful exploration program. Many on our team left the security of major oil companies to help make the vision become reality. When you ask them why, they all give a similar answer. They want to know that each day they can make a difference. They want to be a part of something special. That's what drives our culture and has resulted in the success that differentiates us from many of our peers.

We had early success in the Gulf of Mexico and South Africa, and those projects are now delivering strong production growth. We've drilled discoveries in Gabon, Alaska, Argentina and Tunisia. We strive to create real value through exploration, not just add reserves. To do this, we focus our technical work on accurately quantifying risk and uncertainty and try to have a balanced portfolio of opportunities. We will take a series of "singles and doubles" rather than always "swinging for the fence."

Our exploration team emphasizes doing fundamental geoscience, basic blocking and tackling, to understand the petroleum system of a basin. Then we apply higher technology to high-grade specific plays and prospects. We strive to consistently assess the potential size, risk and economics of all prospects across the entire company. To reduce bias, we put all exploration prospects through a peer review and do look-backs to see if we are delivering the expected result. We encourage our people to speak freely and challenge the system, so peer reviews sometimes involve intense debate, but with a common sense of purpose and a passion to share expertise and improve our chance of success.

The deepwater Gulf of Mexico will remain a major focus area for Pioneer. With seven deepwater discoveries and three others being commercialized, our deepwater team has delivered solid results. In the near term, we will target satellite prospects near our existing fields to take advantage of the infrastructure in place. We have already drilled one satellite discovery and successfully appraised another this year.

The basin is maturing, pushing new drilling into deeper horizons. After about two years of regional work and technical analysis, we've entered a new deepwater play to target deep prospects below salt. This new play has been delivering promising results, and as this report goes to press, we have three wells drilling in the play and are working several other entry opportunities. These early wells offer not only the potential to participate in significant discoveries, but also the ability to gain critical information for the future. The well data combined with our seismic mapping will position us to continue to target prospective acreage via farm-in arrangements from current leaseholders, and participate in federal lease sales in 2006 through 2008 when many expiring leases will become available.

We expanded our U.S. exploration program into Alaska and drilled three successful wells on the North Slope in 2003. We secured additional acreage on the discovery and will look at development options to complete our commercial evaluation this year. We added acreage at the state lease sale in three focus areas that offer a variety of risk profiles and field size potential. The North Slope has a prolific hydrocarbon system, and we believe we entered this area at exactly the right time and have already formed excellent relationships with the existing players.

Pioneer entered West Africa in 1997, leasing the Olowi block in the shallow water offshore Gabon. After acquiring and processing new 3-D seismic data, we drilled four successful wells confirming significant oil and gas in place on the block. We are drilling additional wells to better quantify the reserves in place and will define a development plan for the oil rim this year.

West Africa is one of the world's most promising new exploration areas, with recent discoveries all along the coast. We recently joined forces with Kosmos Energy, a privately held company founded by businessmen and technical professionals with a proven track record in this region. We plan to jointly explore an area along the west coast of Africa extending from Morocco through Angola. By combining the strengths of our two companies, we gain exposure to many new opportunities in this resource-rich region.

Pioneer's newest international venture is focused on the prolific petroleum system of the Ghadames Basin in North Africa. We established a strong acreage position in Tunisia in late 2001 and 2002. Five of the seven wells we've drilled to date have been successful, and with just three wells producing, gross production has reached 9,000 barrels per day. We believe the real upside will be proven through future drilling and plan to drill five to eight wells in 2004 as we seek opportunities to expand our acreage position into neighboring countries.

As we built the exploration team, we were obviously looking for great technical people, but we were looking for *great people* too. The success of our exploration program is the result of the commitment of that team. They all took a risk on Pioneer. They came here to make a difference, and they do.

— CHRIS CHEATWOOD

“In targeting new and emerging plays, preparation and patience drive our efforts.”

A.R. ALAMEDDINE, Executive Vice President, Worldwide Business Development

Over the past several years, Pioneer has built an industry-leading exploration team, and our results show it. We have made property acquisitions in our core areas during this time with good results, while we directed most of our capital to developing discoveries. Now that those discoveries are generating cash, we are expanding our business development team to complement our exploration program and provide more flexibility in achieving our growth goals.

While today’s high commodity prices have created a seller’s market, we see this as a great time to develop a portfolio of opportunities to target when the time is right. To build our program, we’ve put together multi-disciplined teams focused on our existing core areas and are striving to leverage the latest communications and information technology to maximize our efforts and improve results.

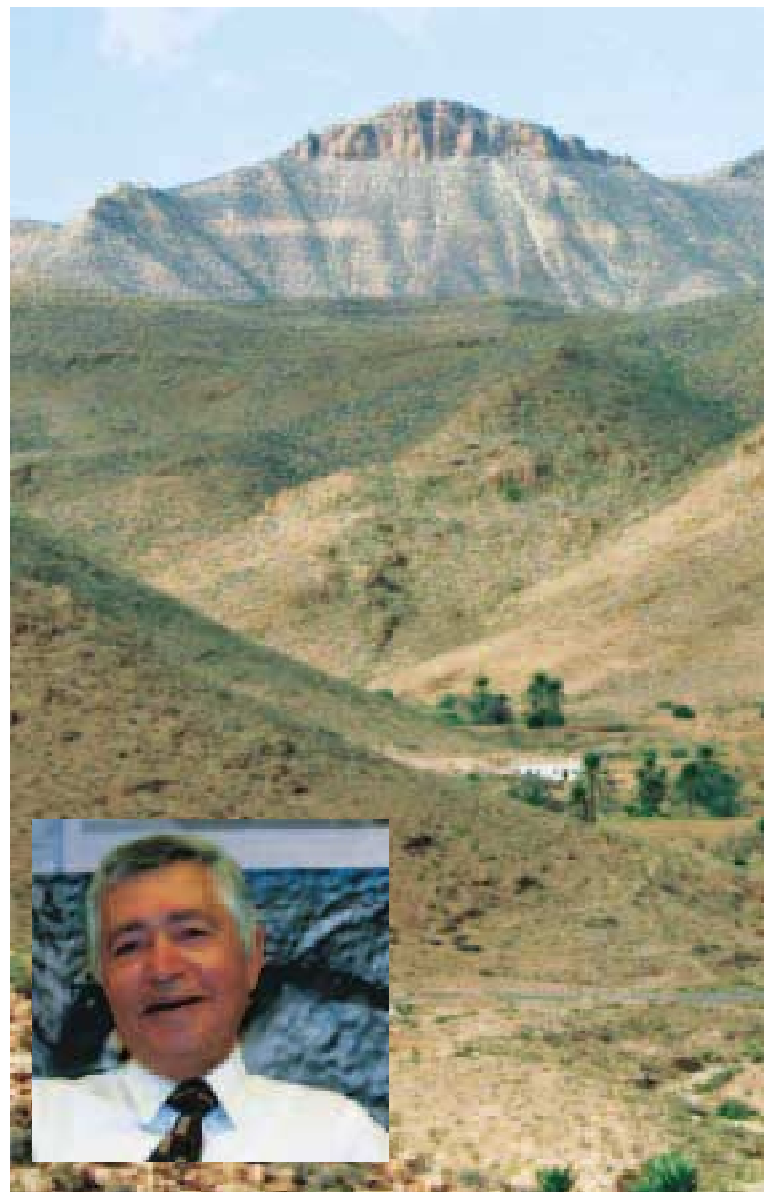
To get to assets that offer both scale and upside in a competitive market, we’ll first seek plays and areas where we have expertise and the best understanding of the technical and commercial keys to value creation. After all, our long-lived core assets were built on an “acquire and exploit” strategy. In targeting new and emerging plays, preparation and patience drive our efforts. When we find an entry point, we count on Pioneer’s dynamic environment to efficiently evaluate and then decisively act to capture the best opportunities.

Ultimately, our success will depend on many talented people and the dynamic and entrepreneurial environment that have combined to create a unique Pioneer culture. We have great confidence that the enthusiasm, energy and creativity of Pioneer’s business and technical professionals will again make a difference as we turn our efforts to this important initiative.

— A.R. (RAY) ALAMEDDINE

ESTABLISHED ACQUISITION TRACK RECORD

AREA	DATE	PRICE ($MM)
DEEPWATER GULF OF MEXICO		
FALCON	2002, 2003	$174
CANYON EXPRESS	2001	48
DEVILS TOWER	2000, 2001	16
		$238
WEST TEXAS		
SPRABERRY	2000, 2001, 2003	$112
TEXAS PANHANDLE		
WEST PANHANDLE	2002	$138
ARGENTINA		
NEUQUEN BASIN	1999, 2001	$55
TOTAL ACQUISITIONS		**$543**



Hashim Alkhersan, Manager of Pioneer Natural Resources Tunisia LTD, has 35 years of experience in the oil and gas industry and has worked more than 25 years in the Middle East.

2003 10-K

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 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
For the transition period from _______ to _______

Commission File Number: 1-13245

Pioneer Natural Resources Company
(Exact name of registrant as specified in its charter)

Delaware	**75-2702753**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
5205 N. O'Connor Blvd., Suite 900, Irving, Texas	**75039**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **(972) 444-9001**

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

Title of each class	Name of each exchange on which registered
Common Stock	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. YES X NO __

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

Indicate by check mark whether the Registrant is an accelerated filer (as defined in Rule 12b-2 of the Act).
YES X NO __

Aggregate market value of the voting common equity held by non-affiliates of the Registrant computed by reference to the price at which the common equity was last sold as of the last business day of the Registrant's most recently completed second fiscal quarter	**$ 3,053,790,906**
Number of shares of Common Stock outstanding as of January 30, 2004	**119,345,550**

Documents Incorporated by Reference:

(1) Proxy Statement for Annual Meeting of Shareholders to be held May 13, 2004 - Referenced in Part III of this report.

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Parts I and II of this annual report on Form 10-K (the "Report") contain forward-looking statements that involve risks and uncertainties. Accordingly, no assurances can be given that the actual events and results will not be materially different than the anticipated results described in the forward looking statements. See "Item 1. Business - Competition, Markets and Regulations" and "Item 1. Business - Risks Associated with Business Activities" for a description of various factors that could materially affect the ability of Pioneer Natural Resources Company to achieve the anticipated results described in the forward-looking statements.

Definitions of Oil and Gas Terms and Conventions Used Herein

Within this Report, the following oil and gas terms and conventions have specific meanings: **"Bbl"** means a standard barrel containing 42 United States gallons; **"BOE"** means a barrel of oil equivalent and is a standard convention used to express oil and gas volumes on a comparable oil equivalent basis; **"Btu"** means British thermal unit and is a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit; **"LIBOR"** means London Interbank Offered Rate, which is a market rate of interest; **"MMBtu"** means one million Btus; **"MBbl"** means one thousand Bbls; **"MBOE"** means one thousand BOE; **"MMBOE"** means one million BOE; **"Mcf"** means one thousand cubic feet and is a measure of natural gas volume; **"MMcf"** means one million cubic feet; **"Bcf"** means one billion cubic feet; **"NGL"** means natural gas liquid; **"NYMEX"** means The New York Mercantile Exchange; **"proved reserves"** mean 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, *i.e.*, prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recoverytechniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

"Standardized Measure" means the after-tax present value of estimated future net revenues of proved reserves, determined in accordance with the rules and regulations of the United States Securities and Exchange Commission (the **"SEC"**), using prices and costs in effect at the specified date and a 10 percent discount rate; **"acquisition and finding cost per BOE"** means total costs incurred divided by the summation of proved reserves attributable to revisions of previous estimates, purchases of minerals-in-place and new discoveries and extensions; and **"reserve replacement percentage"** means, expressed as a percentage, the summation of annual proved reserves, on a BOE basis, attributable to revisions of previous estimates, purchases of minerals-in-place and new discoveries and extensions divided by annual production of oil, NGLs and gas, on a BOE basis.

Gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of gas to 1.0 Bbl of oil or NGL.

With respect to information on the working interest in wells, drilling locations and acreage, **"net"** wells, drilling locations and acres are determined by multiplying **"gross"** wells, drilling locations and acres by Pioneer Natural Resources Company's working interest in such wells, drilling locations or acres. Unless otherwise specified, wells, drilling locations and acreage statistics quoted herein represent gross wells, drilling locations or acres; and, all currency amounts are expressed in U.S. dollars.

PART I

ITEM 1. BUSINESS

General

Pioneer Natural Resources Company (the "Company" or "Pioneer") is a Delaware corporation whose common stock is listed and traded on the New York Stock Exchange. Pioneer is an oil and gas exploration and production company with ownership interests in oil and gas properties located in the United States, Argentina, Canada, Gabon, South Africa and Tunisia.

The Company's executive offices are located at 5205 N. O'Connor Blvd., Suite 900, Irving, Texas 75039. The Company's telephone number is (972) 444-9001. The Company maintains other offices in Midland, Texas; Buenos Aires, Argentina; Calgary, Canada; Capetown, South Africa; Tunis, Tunisia; and Libreville, Gabon. At December 31, 2003, the Company had 1,014 employees, 505 of whom were employed in field and plant operations.

Available Information

Pioneer files annual, quarterly and current reports, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934. The public may read and copy any materials that Pioneer files with the SEC at the SEC's Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an Internet website that contains reports, proxy and information statements, and other information regarding issuers, including Pioneer, that file electronically with the SEC. The public can obtain any documents that Pioneer files with the SEC at http://www.sec.gov.

The Company also makes available free of charge on or through its Internet website (http://www.pioneernrc.com) its Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after it electronically files such material with, or furnishes it to, the SEC.

Mission and Strategies

The Company's mission is to provide shareholders with superior investment returns through strategies that maximize Pioneer's long-term profitability and net asset value. The strategies employed to achieve this mission are predicated on maintaining financial flexibility and capital allocation discipline. Historically, these strategies have been anchored by the Company's long-lived Spraberry oil field and Hugoton and West Panhandle gas fields' reserves and production. Underlying these fields are approximately 65 percent of the Company's proved oil and gas reserves as of December 31, 2003. These fields have a remaining productive life in excess of 40 years. The stable base of oil and gas production from these fields, combined with the deepwater Gulf of Mexico Canyon Express, Falcon and Harrier gas projects which began production in September 2002, March 2003 and January 2004, respectively, and the Sable oil discovery in South Africa which began production in August 2003 will generate the operating cash flows that will allow the Company to improve its financial flexibility in 2004. These activities will be further enhanced by initial production in mid-2004 from the Company's Devils Tower oil discovery and the Raptor and Tomahawk gas discoveries, all located in the deepwater Gulf of Mexico.

The above exploration successes represent some of the results of the Company's decision to selectively reinvest capital from the long-lived Spraberry, Hugoton and West Panhandle fields to areas offering superior investment returns. Similarly, the Company will continue to: (a) selectively explore for and develop proved reserve discoveries in areas that offer superior reserve growth and profitability potential; (b) evaluate opportunities to acquire oil and gas properties under terms that will complement the Company's exploration and development drilling activities; (c) invest in the personnel and technology necessary to maximize the Company's exploration and development successes; and (d) enhance liquidity, allowing the Company to take advantage of future exploration, development and acquisition opportunities. The Company is committed to continuing to enhance shareholder investment returns through adherence to these strategies.

Business Activities

The Company is an independent oil and gas exploration and production company. Pioneer's purpose is to competitively and profitably explore for, develop and produce oil, NGL and gas reserves. In so doing, the Company sells homogenous oil, NGL and gas units which, except for geographic and relatively minor qualitative differentials, cannot be significantly differentiated from units offered for sale by the Company's competitors. Competitive advantage is gained in the oil and gas exploration and development industry through superior capital investment decisions, technological innovation and price and cost management.

Petroleum industry. The petroleum industry has been characterized by fluctuating oil, NGL and gas commodity prices and relatively stable supplier costs during the three years ended December 31, 2003. During and just prior to 2000, the Organization of Petroleum Exporting Countries ("OPEC") and certain other oil exporting nations reduced their oil export volumes. Those reductions in oil export volumes had a positive impact on world oil prices, as did overall gas supply and demand fundamentals on North American gas prices. During 2002,world oil prices increased in response to political unrest and supply disruptions in the Middle East and Venezuela while North American gas prices improved as market fundamentals strengthened. During 2003, world oil and North American gas supply and demand fundamentals continued to strengthen. Significant factors that will impact 2004 commodity prices include the final resolution of issues currently impacting Iraq and the Middle East in general, the extent to which members of OPEC and other oil exporting nations are able to continue to manage oil supply through export quotas and overall North American gas supply and demand fundamentals. To mitigate the impact of commodity price volatility on the Company's net asset value, Pioneer utilizes commodity hedge contracts. See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the impact to oil and gas revenues during the years ended December 31, 2003, 2002 and 2001 from the Company's hedging activities and the Company's open hedge positions at December 31, 2003.

The Company. The Company's asset base is anchored by the Spraberry oil field located in West Texas, the Hugoton gas field located in Southwest Kansas and the West Panhandle gas field located in the Texas Panhandle. Complementing these areas, the Company has exploration and development opportunities and/or oil and gas production activities in the Gulf of Mexico, the onshore Gulf Coast area and in Alaska, and internationally in Argentina, Canada, Gabon, South Africa and Tunisia. Combined, these assets create a portfolio of resources and opportunities that are well balanced among oil, NGLs and gas, and that are also well balanced between long-lived, dependable production and exploration and development opportunities. Additionally, the Company has a team of dedicated employees that represent the professional disciplines and sciences that will allow Pioneer to maximize the long-term profitability and net asset value inherent in its physical assets.

The Company provides administrative, financial and management support to United States and foreign subsidiaries that explore for, develop and produce oil, NGL and gas reserves. Production operations are principally located domestically in Texas, Kansas, Louisiana and the Gulf of Mexico, and internationally in Argentina, Canada, South Africa and Tunisia.

Production. The Company focuses its efforts towards maximizing its average daily production of oil, NGLs and gas through development drilling, production enhancement activities and acquisitions of producing properties while minimizing the controllable costs associated with the production activities. During the year ended December 31, 2003, the Company's average daily oil, NGL and gas production increased as a result of (i) a full year of gas production from the Company's Canyon Express gas project in the deepwater Gulf of Mexico, (ii) gas production since March 2003 from the Company's Falcon gas field in the deepwater Gulf of Mexico, (iii) increased production from Argentina primarily resulting from the resumption of oil drilling activities since the third quarter of 2002, (iv) oil production since May 2003 from the Company's Adam field in Tunisia and (v) oil production since August 2003 from the Company's Sable field offshore South Africa. These increases more than offset normal production declines. During 2002, the Company's average daily oil, NGL and gas production decreased primarily due to normal production declines, reduced Argentine demand for gas, the Company's curtailment of Argentine drilling activities during the first half of 2002 and the December 2001 sale of the Company's Rycroft/Spirit River field in Canada. During 2001, the Company's average daily oil, NGL and gas production decreased primarily as a result of oil and gas property divestitures that were supportive of the Company's debt reduction goal. Production, price and cost information with respect to the Company's properties for each of the years ended December 31, 2003, 2002 and 2001 is set forth under "Item 2. Properties - Selected Oil and Gas Information - Production, Price and Cost Data".

Drilling activities. The Company seeks to increase its oil and gas reserves, production and cash flow through exploratory and development drilling and by conducting other production enhancement activities, such as well recompletions. During the three years ended December 31, 2003, the Company drilled 1,002 gross (744.1 net) wells, 86 percent of which were successfully completed as productive wells, at a total drilling cost (net to the Company's interest) of $1.5 billion. During 2003, the Company drilled 383 gross (338.8 net) wells. The Company's current 2004 capital expenditure budget is expected to range from $550 million to $600 million. Excluding the 2003 acquisitions, the Company's 2004 capital expenditure budget is comparable to 2003 costs incurred for oil and gas producing activities. The Company has allocated the budgeted 2004 capital expenditures as follows: 65 percent to development drilling and facility activities and 35 percent to exploration activities.

The Company believes that its current property base provides a substantial inventory of prospects for future reserve, production and cash flow growth. The Company's proved reserves as of December 31, 2003 include proved undeveloped reserves and proved developed reserves that are behind pipe of 188.9 million Bbls of oil and NGLs and 670.8 Bcf of gas. Development of these reserves will require future capital expenditures. The timing of the development of these reserves will be dependent upon the commodity price environment, the Company's expected operating cash flows and the Company's financial condition. The Company believes that its current portfolio of undeveloped prospects and reserves provides attractive development and exploration opportunities for at least the next three to five years.

Exploratory activities. Since 1998, the Company has devoted significant efforts and resources to hiring and developing a highly skilled exploration staff as well as acquiring and drilling a portfolio of exploration opportunities. The Company's commitment to exploration has resulted in significant discoveries during this time period, such as the 1998 Sable oil field discovery in South Africa; the 1999 Aconcagua, 2000 Devils Tower, 2001 Falcon and 2003 Harrier, Tomahawk and Raptor discoveries in the deepwater Gulf of Mexico; the 2001 Olowi permit discovery located in the Southern Gabon basin; and the 2002 Borj El Khadra permit discovery in the Ghadames basin onshore Southern Tunisia. The Company currently anticipates that its 2004 exploration efforts will be approximately 35 percent of total 2004 capital expenditures and will be concentrated domestically in the Gulf of Mexico, and internationally in Argentina, Canada, Gabon and Tunisia. Exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons than development drilling or enhanced recovery activities. See "Item 1. Business - Risks Associated with Business Activities - Drilling activities" below.

Acquisition activities. The Company regularly seeks to acquire properties that complement its operations, provide exploration and development opportunities and potentially provide superior returns on investment. In addition, the Company pursues strategic acquisitions that will allow the Company to expand into new geographical areas that feature producing properties and provide exploration/exploitation opportunities. During the years ended December 31, 2003, 2002 and 2001, the Company expended $151.0 million, $195.5 million and $170.8 million, respectively, of acquisition capital to purchase additional interests in, and other assets associated with, its existing assets and to acquire new prospects for future exploration activities. See Note D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of the Company's acquisitions during 2003, 2002 and 2001.

The Company periodically evaluates and pursues acquisition opportunities (including opportunities to acquire particular oil and gas properties or related assets; entities owning oil and gas properties or related assets; and opportunities to engage in mergers, consolidations or other business combinations with such entities) and at any given time may be in various stages of evaluating such opportunities. Such stages may take the form of internal financial analysis, oil and gas reserve analysis, due diligence, the submission of an indication of interest, preliminary negotiations, negotiation of a letter of intent or negotiation of a definitive agreement.

Asset divestitures. The Company regularly reviews its asset base for the purpose of identifying non-strategic assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. While the Company generally does not dispose of assets solely for the purpose of reducing debt, such dispositions can have the result of furthering the Company's objective of financial flexibility through reduced debt levels.

During the years ended December 31, 2003, 2002 and 2001, the Company's divestitures consisted of the early termination of derivative hedge contracts and the sales of oil and gas properties and other assets for net proceeds of $35.7 million, $118.9 million and $113.5 million, respectively, which resulted in 2003, 2002 and 2001 net divestiture gains of $1.3 million, $4.4 million and $7.7 million, respectively. The net cash proceeds from the 2003, 2002 and 2001 asset dispositions were primarily used to fund additions to oil and gas properties or to reduce the Company's outstanding indebtedness. See Note N of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for specific information regarding the Company's asset divestitures.

The Company anticipates that it will continue to sell non-strategic properties or other assets from time to time to increase capital resources available for other activities, to achieve operating and administrative efficiencies and to improve profitability.

Operations by Geographic Area

The Company operates in one industry segment. During the three years ended December 31, 2003, the Company had oil and gas producing and development activities in the United States, Argentina, Canada, Gabon, South Africa and Tunisia, and had exploration activities in the United States, Argentina, Canada, Gabon, South Africa and Tunisia. See Note R of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for geographic operating segment information, including results of operations and segment assets.

Marketing of Production

General. Production from the Company's properties is marketed using methods that are consistent with industry practices. Sales prices for oil, NGL and gas production are negotiated based on factors normally considered in the industry, such as the index or spot price for gas or the posted price for oil, price regulations, distance from the well to the pipeline, well pressure, estimated reserves, commodity quality and prevailing supply conditions.

Significant purchasers. During the year ended December 31, 2003, the Company's primary purchasers of oil were ExxonMobil Corporation ("ExxonMobil") and Plains Marketing LP ("Plains"), the Company's primary purchaser of NGLs was Enterprise Products Operating L.P. ("Enterprise") and the Company's primary purchasers of gas were Williams Energy Services ("Williams") and Conoco Phillips. Approximately 16 percent, eight percent and seven percent of the Company's 2003 combined oil, NGL and gas revenues were attributable to sales to Williams, Conoco Phillips and Enterprise, respectively, and approximately five percent of combined oil, NGL and gas revenues of 2003 were attributable to sales to ExxonMobil and Plains. The Company is of the opinion that the loss of any one purchaser would not have an adverse effect on its ability to sell its oil, NGL and gas production.

Hedging activities. The Company utilizes commodity swap and collar contracts in order to (i) reduce the effect of price volatility on the commodities the Company produces and sells, (ii) support the Company's annual capital budgeting and expenditure plans and (iii) reduce commodity price risk associated with certain capital projects. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" for a description of the Company's hedging activities, "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information concerning the impact on oil and gas revenues during the years ended December 31, 2003, 2002 and 2001 from the Company's commodity hedging activities and the Company's open commodity hedge positions at December 31, 2003.

Competition, Markets and Regulations

Competition. The oil and gas industry is highly competitive. A large number of companies and individuals engage in the exploration for and development of oil and gas properties, and there is a high degree of competition for oil and gas properties suitable for development or exploration. Acquisitions of oil and gas properties have been an important element of the Company's growth. The Company intends to continue to acquire oil and gas properties that complement its operations, provide exploration and development opportunities and potentially provide superior return on investment. The principal competitive factors in the acquisition of oil and gas properties include the staff and data necessary to identify, investigate and purchase such properties and the financial resources necessary to acquire and develop the properties. Many of the Company's competitors are substantially larger and have financial and other resources greater than those of the Company.

Markets. The Company's ability to produce and market oil, NGLs and gas profitably depends on numerous factors beyond the Company's control. The effect of these factors cannot be accurately predicted or anticipated. Although the Company cannot predict the occurrence of events that may affect these commodity prices or the degree to which these prices will be affected, the prices for any commodity that the Company produces will generally approximate current market prices in the geographic region of the production.

Governmental regulations. Enterprises that sell securities in public markets are subject to regulatory oversight by agencies such as the SEC. This regulatory oversight imposes on the Company the responsibility for establishing and maintaining disclosure controls and procedures that will ensure that material information relating to the Company and its consolidated subsidiaries is made known to the Company's management and that the financial statements and other financial information included in this Report do not contain any untrue statement of a material fact, or omit to state a material fact, necessary to make the statements made in this Report not misleading.

Oil and gas exploration and production operations are also subject to various types of regulation by local, state, federal and foreign agencies. Additionally, the Company's operations are subject to state conservation laws and regulations, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum rates of production from wells and the regulation of spacing, plugging and abandonment of wells. States and foreign governments generally impose a production or severance tax with respect to productionand sale of oil and gas within their respective jurisdictions. The regulatory burden on the oil and gas industry increases the Company's cost of doing business and, consequently, affects its profitability.

Additional proposals and proceedings that might affect the oil and gas industry are considered from time to time by Congress, the Federal Energy Regulatory Commission, state regulatory bodies, the courts and foreign governments. The Company cannot predict when or if any such proposals might become effective or their effect, if any, on the Company's operations.

Environmental and health controls. The Company's operations are subject to numerous federal, state, local and foreign laws and regulations relating to environmental and health protection. These laws andregulations may require the acquisition of a permit before drilling commences, restrict the type, 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 oil and gas operations. These laws and regulations may also restrict air emissions or other discharges resulting from the operation of gas processing plants, pipeline systems and other facilities that the Company owns. Although the Company believes that compliance with environmental laws and regulations will not have a material adverse effect on its future results of operations or financial condition, risks of substantial costs and liabilities are inherent in oil and gas operations, and there can be no assurance that significant costs and liabilities, including potential criminal penalties, will not be incurred. Moreover, it is possible that other developments, such as stricter environmental laws and regulations or claims for damages to property or persons resulting from the Company's operations, could result in substantial costs and liabilities.

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain classesof persons with respect to 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 disposed or arranged for the disposal of hazardous substances released 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 Company generates wastes, including hazardous wastes, that are subject to the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The United States Environmental Protection Agency and various state agencies have limited the approved methods of disposal for certain hazardous and non-hazardous wastes. Furthermore, certain wastes generated by the Company's oil and gas operations that are currently exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes, and therefore be subject to more rigorous and costly operating and disposal requirements.

The Company currently owns or leases, and has in the pastowned or leased, properties that for many years have been used for the exploration and production of oil and gas reserves. Although the Company has used 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 the Company or on or under other locations where such wastes have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under the Company's control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under such laws, the Company could be required to remove or remediate previously disposed wastes or property contamination or to perform remedial plugging operations to prevent future contamination.

Federal regulations require certain owners or operators of facilities that store or otherwise handle oil, such as the Company, to prepare and implement spill prevention control plans, countermeasure plans and facility response plans relating to the possible discharge of oil into surface waters. The Oil Pollution Prevention Act of 1990 ("OPA") amends certain provisions of the federal Water Pollution Control Act of 1972, commonly referred to as the Clean Water Act ("CWA"), and other statutes as they pertain to the prevention of and response to oil spills into navigable waters. The OPA subjects owners of facilities to strict joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil to surface waters. The CWA provides penalties for any discharges of petroleum products in reportable quantities and imposes substantial liability for the costs of removing a spill. OPA requires responsible parties to establish and maintain evidence of financial responsibility to cover removal costs and damages resulting from an oil spill. OPA calls for a financial responsibility of $35 million to cover pollution cleanup for offshore facilities. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities in the case of releases of petroleum or its derivatives into surface waters or into the ground. The Company does not believe that the OPA, CWA or related state laws are any more burdensome to it than they are to other similarly situated oil and gas companies.

Many states in which the Company operates regulate naturally occurring radioactive materials ("NORM") and NORM wastes that are generated in connection with oil and gas exploration and production activities. NORM wastes typically consist of very low-level radioactive substances that become concentrated in pipe scale and in production equipment. Certain state regulations require the testing of pipes and production equipment for the presence of NORM, the licensing of NORM-contaminated facilities and the careful handling and disposal of NORM wastes. The regulation of NORM has minimal effect on the Company's operations because the Company generates only small quantities of NORM on an annual basis.

The Company does not believe that its environmental risks are materially different from those of comparable companies in the oil and gas industry. Nevertheless, no assurance can be given that environmental laws will not result in a curtailment of production or processing, a material increase in the costs of production, development, exploration or processing or otherwise adversely affect the Company's future results of operations and financial condition.

The Company employs an environmental director and environmental specialists charged with monitoring environmental and regulatory compliance. The Company performs an environmental review as part of the due diligence work on potential acquisitions. The Company is not aware of any material environmental legal proceedings pending against it or any material environmental liabilities to which it may be subject.

Risks Associated with Business Activities

The nature of the business activities conducted by the Company subjects it to certain hazards and risks. The following is a summary of some of the material risks relating to the Company's business activities.

Commodity prices. The Company's revenues, profitability, cash flow and future rate of growth are highly dependent on oil and gas prices, which are affected by numerous factors beyond the Company's control. Oil and gas prices historically have been very volatile. A significant downward trend in commodity prices would have a material adverse effect on the Company's revenues, profitability and cash flow and could, under certain circumstances, result in a reduction in the carrying value of the Company's oil and gas properties and the recognition of a deferred tax asset valuation allowance or an increase to the Company's deferred tax asset valuation allowances, depending on the Company's tax attributes in each country in which it has activities.

Drilling activities. Drilling involves numerous risks, including the risk that no commercially productive oil or gas reservoirs will be encountered. The cost of drilling, completing and operating wells is often uncertain and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including unexpected drilling conditions, pressure or irregularities in formations, equipment failures or accidents, adverse weather conditions and shortages or delays in the delivery of equipment. The Company's future drilling activities may not be successful and, if unsuccessful, such failure could have an adverse effect on the Company's future results of operations and financial condition. While all drilling, whether developmental or exploratory, involves these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. Because of the percentage of the Company's capital budget devoted to higher risk exploratory projects, it is likely that the Company will continue to experience exploration and abandonment expense.

Unproved properties. At December 31, 2003 and 2002, the Company carried unproved property costs of $179.8 million and $219.1 million, respectively. Generally accepted accounting principles require periodic evaluation of these costs on a project-by-project basis in comparison to their estimated value. These evaluations will be affected by the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of the leases, contracts and permits appurtenant to such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, the Company will recognize noncash charges in the earnings of future periods.

Acquisitions. Acquisitions of producing oil and gas properties have been a key element of the Company's growth. The Company's growth following the full development of its existing property base could be impeded if it is unable to acquire additional oil and gas reserves on a profitable basis. The success of any acquisition will depend on a number of factors, including the ability to estimate accurately the recoverable volumes of reserves, rates of future production and future net revenues attainable from the reserves and to assess possible environmental liabilities. All of these factors affect whether an acquisition will ultimately generate cash flows sufficient to provide a suitable return on investment. Even though the Company performs a review of the properties it seeks to acquire that it believes is consistent with industry practices, such reviews are often limited in scope.

Divestitures. The Company regularly reviews its property base for the purpose of identifying non-strategic assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. Various factors could materially affect the ability of the Company to dispose of non-strategic assets, including the availability of purchasers willing to purchase the non-strategic assets at prices acceptable to the Company.

Operation of natural gas processing plants. As of December 31, 2003, the Company owned interests in 11 natural gas processing plants and five treating facilities. The Company operates seven of the plants and all five treating facilities. There are significant risks associated with the operation of natural gas processing plants. Gas and NGLs are volatile and explosive and may include carcinogens. Damage to or misoperation of a gas processing plant or facility could result in an explosion or the discharge of toxic gases, which could result in significant damage claims in addition to interrupting a revenue source.

Operating hazards and uninsured losses. The Company's operations are subject to all the risks normally incident to the oil and gas exploration and production business, including blowouts, cratering, explosions and pollution and other environmental damage, any of which could result in substantial losses to the Company due to injury or loss of life, damage to or destruction of wells, production facilities or other property, clean-up responsibilities, regulatory investigations and penalties and suspension of operations. Although the Company currently maintains insurance coverage that it considers reasonable and that is similar to that maintained by comparable companies in the oil and gas industry, it is not fully insured against certain of these risks, either because such insurance is not available or because of the high premium costs associated with obtaining such insurance.

Environmental. The oil and gas business is subject to environmental hazards, such as oil spills, produced water spills, gas leaks and ruptures and discharges of toxic substances or gases that could expose the Company to substantial liability due to pollution and other environmental damage. A variety of federal, state and foreign laws and regulations govern the environmental aspects of the oil and gas business. Noncompliance with these laws and regulations may subject the Company to penalties, damages or other liabilities, and compliance may increase the cost of the Company's operations. Such laws and regulations may also affect the costs of acquisitions. See "Item 1. Business - Competition, Markets and Regulation - Environmental and health controls" above for additional discussion related to environmental risks.

The Company does not believe that its environmental risks are materially different from those of comparable companies in the oil and gas industry. Nevertheless, no assurance can be given that future environmental laws will not result in a curtailment of production or processing, a material increase in the costs of production, development, exploration or processing or otherwise adversely affect the Company's future operations and financial condition. Pollution and similar environmental risks generally are not fully insurable.

Debt restrictions and availability. The Company is a borrower under fixed term senior notes and a corporate credit facility. The terms of the Company's borrowings under the senior notes and the corporate credit facility specify scheduled debt repayments and require the Company to comply with certain associated covenants and restrictions. The Company's ability to comply with the debt repayment terms, associated covenants and restrictions is dependent on, among other things, factors outside the Company's direct control, such as commodity prices, interest rates and competition for available debt financing. See Note E of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the Company's outstanding debt as of December 31, 2003 and the terms associated therewith.

Competition. The oil and gas industry is highly competitive. The Company competes with other companies, producers and operators for acquisitions and in the exploration, development, production and marketing of oil and gas. Some of these competitors have substantially greater financial and other resources than the Company. See "Item 1. Business - Competition, Markets and Regulation - Competition" above for additional discussion regarding competition.

Government regulation. The Company's business is regulated by a variety of federal, state, local and foreign laws and regulations. There can be no assurance that present or future regulations will not adversely affect the Company's business and operations. See "Item 1. Business - Competition, Markets and Regulation - Governmental regulations" above for additional discussion regarding government regulation.

International operations. At December 31, 2003, approximately 21 percent of the Company's proved reserves of oil, NGLs and gas were located outside the United States (16 percent in Argentina, three percent in Africa and two percent in Canada). The success and profitability of international operations may be adversely affected by risks associated with international activities, including economic and labor conditions, political instability, tax laws (including host-country export, excise and income taxes and United States taxes on foreign subsidiaries) and changes in the value of the U.S. dollar versus the local currencies in which oil and gas producing activities may be denominated. To the extent that the Company is involved in international activities, changes in exchange rates may adversely affect the Company's future results of operations and financial condition. See Critical Accounting Estimates included in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information specific to Argentina's economic and political situation.

Estimates of reserves and future net revenues. Numerous uncertainties exist in estimating quantities of proved reserves and future net revenues therefrom. The estimates of proved reserves and related future net revenues set forth in this Report are based on various assumptions, which may ultimately prove to be inaccurate. Therefore, such estimates should not be construed as accurate estimates of the current market value of the Company's proved reserves.

ITEM 2. PROPERTIES

The information included in this Report about the Company's oil, NGL and gas reserves as of December 31, 2003 was based on reserve reports audited by Netherland, Sewell & Associates, Inc. for the Company's major properties in the United States, Argentina, Canada and South Africa and reserve reports prepared by the Company's engineers for all other properties. The reserve audit conducted by Netherland, Sewell & Associates, Inc. in aggregate represented 87 percent of the Company's estimated proved quantities of reserves as of December 31, 2003. The information included in this Report about the Company's oil, NGL and gas reserves as of December 31, 2002 was based on reserve reports audited by Netherland, Sewell & Associates, Inc. for the Company's major properties in the United States, Canada and South Africa, reserve reports audited by Gaffney, Cline & Associates, Inc. for the Company's properties located in the Neuquen Basin in Argentina and reserve reports prepared by the Company's engineers for all other properties. The reserve audits conducted by Netherland, Sewell & Associates, Inc. and Gaffney, Cline & Associates, Inc., in aggregate, represented 71 percent of the Company's estimated proved quantities of reserves as of December 31, 2002. The information in this Report about the Company's oil, NGL and gas reserves as of December 31, 2001 was based on proved reserves as determined by the Company's engineers.

Numerous uncertainties exist in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond the Company's control. This Report contains estimates of the Company's proved oil and gas reserves and the related future net revenues, which are based on various assumptions, including those prescribed by the SEC. Actual future production, oil and gas prices, revenues, taxes, capital expenditures, operating expenses and quantities of recoverable oil and gas reserves may vary substantially from those assumed in the estimates and could materially affect the estimated quantities and related Standardized Measure of proved reserves set forth in this Report. In addition, the Company's reserves may be subject to downward or upward revisions based on production performance, purchases or sales of properties, results of future exploration and development activities, prevailing oil and gas prices and other factors. Therefore, estimates of the Standardized Measure of proved reserves should not be construed as accurate estimates of the current market value of the Company's assets.

Standardized Measure is a reporting convention that provides a common basis for comparing oil and gas companies subject to the rules and regulations of the SEC. It requires the use of oil and gas spot prices prevailing as of the date of computation. Consequently, it may not reflect the prices ordinarily received or that will be received for oil and gas production because of seasonal price fluctuations or other varying market conditions. Standardized Measures as of any date are not necessarily indicative of future results of operations. Accordingly, estimates included herein of future net revenues may be materially different from the net revenues that are ultimately received.

The Company did not provide estimates of total proved oil and gas reserves during the years ended December 31, 2003, 2002 or 2001 to any federal authority or agency, other than the SEC.

Proved Reserves

The Company's proved reserves totaled 789.1 million BOE at December 31, 2003, 736.7 million BOE at December 31, 2002 and 671.4 million BOE at December 31, 2001, representing $4.6 billion, $4.1 billion and $2.5 billion, respectively, of Standardized Measure or $6.0 billion, $5.1 billion and $2.5 billion, respectively, on a pre-tax basis. The seven and 11 percent increases in proved reserve volumes and Standardized Measure, respectively, during 2003 were primarily due to two core area acquisitions, discoveries in Gabon, the deepwater Gulf of Mexico and Tunisia and positive reserve revisions due to increased commodity prices extending the estimated economic life of various properties, increased recoverable reserve estimates based on well performance and the addition of reserves resulting from the Company' expanded development drilling program. The ten and 65 percent increases in proved reserve volumes and Standardized Measure, respectively, during 2002 were attributable to an increase in commodity prices, the purchase of incremental interests in two core assets and the Company's successful capital investments.

On a BOE basis, 65 percent of the Company's total proved reserves at December 31, 2003 were proved developed reserves. Based on reserve information as of December 31, 2003, and using the Company's production information for the year then ended, the reserve-to-production ratio associated with the Company's proved reserves was 14.0 years on a BOE basis. The following table provides information regarding the Company's proved reserves and average daily production by geographic area as of and for the year ended December 31, 2003:

PROVED OIL AND GAS RESERVES AND AVERAGE DAILY PRODUCTION

	Proved Reserves as of December 31, 2003				2003 Average Daily Production (a)		
	Oil & NGLs (MBbls)	Gas (MMcf)	MBOE	Standardized Measure (in thousands)	Oil & NGLs (Bbls)	Gas (Mcf)	BOE
United States	362,751	1,553,976	621,747	$ 3,797,488	44,863	445,609	119,129
Argentina	33,469	549,856	125,112	443,118	10,005	94,128	25,694
Canada	2,407	93,829	18,045	218,419	1,017	41,669	7,962
Africa	24,154	-	24,154	124,228	1,981	-	1,981
Total	422,781	2,197,661	789,058	$ 4,583,253	57,866	581,406	154,766

(a) The 2003 average daily production was calculated using a 365-day year and without making pro forma adjustments for any acquisitions, divestitures or drilling activity that occurred during the year.

Finding Cost and Reserve Replacement

The Company's acquisition and finding costs per BOE for the years ended December 31, 2003,2002 and 2001 were $6.64, $6.30 and $7.49 per BOE, respectively. The average acquisition and finding cost for the three-year period ended December 31, 2003 was $6.76 per BOE, representing an eight percent increase over the 2002 three-year average rate of $6.24 per BOE.

During the year ended December 31, 2003, the Company replaced 193 percent of its annual production on a BOE basis (299 percent for oil and NGLs and 129 percent for gas). During 2002, the Company replaced 258 percent of its annual production on a BOE basis (384 percent for oil and NGLs and 144 percent for gas). During 2001, the Company replaced 208 percent of its annual production on a BOE basis (169 percent for oil and NGLs and 245 percent for gas). The Company's 2003 and 2002 reserve replacement percentages were the result of revisions of previous estimates including revisions related to changes in commodity prices, asset purchases and new discoveries andfield extensions. The Company's 2001 reserve replacement percentage was primarily impactedby asset purchases and new discoveries and field extensions.

Description of Properties

As of December 31, 2003, the Company has production, development and/or exploration operations in the United States, Argentina, Canada, Gabon, South Africa and Tunisia.

Domestic. The Company's domestic operations are located in the Permian Basin, Mid-Continent, Gulf of Mexico and onshore Gulf Coast areas of the United States. The Company also has unproved properties in Alaska. Approximately 83 percent of the Company's domestic proved reserves at December 31, 2003 are located in the Spraberry, Hugoton and West Panhandle fields. These mature fields generate substantial operating cash flow and have a large portfolio of low risk infill drilling opportunities. The cash flows generated from these fields provide funding for the Company's other development and exploration activities both domestically and internationally. During the year ended December 31, 2003, the Company expended $563.0 million in domestic acquisition, exploration and development drilling activities. The Company has budgeted approximately $427 million for domestic exploration and development drilling expenditures for 2004.

Spraberry field. The Spraberry field was discovered in 1949 and encompasses eight counties in West Texas. The field is approximately 150 miles long and 75 miles wide at its widest point. The oil produced is West Texas Intermediate Sweet, and the gas produced is casinghead gas with an average energy content of 1,400 Btu per Mcf. The oil and gas are produced primarily from three formations, the upper and lower Spraberry and the Dean, at depths ranging from 6,700 feet to 9,200 feet. Recently, the Company has been adding the Wolfcamp formation at depths ranging from 9,300 feet to 10,300 feet to selected completions with successful results. The center of the Spraberry field was unitized in the late 1950s and early 1960s by the major oil companies; however, until the late 1980s there was very limited development activity in the field. The Company believes the area offers excellent opportunities to enhance oil and gas reserves because of the numerous undeveloped infill drilling locations, many of which are reflected in the Company's proved undeveloped reserves, and the ability to reduce operating expenses through economies of scale.

During the year ended December 31, 2003, the Company placed 123 Spraberry wells on production and drilled one developmental dry hole. The Company plans to drill approximately 114 development wells in the Spraberry field during 2004.

Hugoton field. The Hugoton field in southwest Kansas is one of the largest producing gas fields in the continental United States. The gas is produced from the Chase and Council Grove formations at depths ranging from 2,700 feet to 3,000 feet. The Company's Hugoton properties are located on approximately 257,000 gross acres (237,000 net acres), covering approximately 400 square miles. The Company has working interests in approximately 1,200 wells in the Hugoton field, about 1,000 of which it operates, and partial royalty interests in approximately 500 wells. The Company owns substantially all of the gathering and processing facilities, primarily the Satanta plant, that service its production from the Hugoton field. Such ownership allows the Company to control the production, gathering, processing and sale of its gas and NGL production.

The Company's Hugoton operated wells are capable of producing approximately 90 MMcf of wet gas per day (i.e., gas production at the wellhead before processing and before reduction for royalties), although actual production in the Hugoton field is limited by allowables set by state regulators. The Company estimates that it and other major producers in the Hugoton field produced at or near capacity during the year ended December 31, 2003. During 2003, the Company placed 18 development wells on production, drilled one developmental dry hole and had one well in progress as of December 31, 2003 in the Hugoton field. The plans for 2004 include drilling approximately 20 development wells.

The Company is continuing to evaluate the feasibility of infill drilling into the Council Grove Formation and may submit an application to the Kansas Corporation Commission to allow infill drilling. Such infill drilling may increase production from the Company's Hugoton properties. However, until an application has been submitted and approved, the Company will not reflect any of the infill drilling locations as proved undeveloped reserves. There can be no assurance that the application will be filed or approved, or as to the timing of such approval if granted.

West Panhandle field. The West Panhandle properties are located in the panhandle region of Texas where initial production commenced in 1918. These stable, long-lived reserves are attributable to the Red Cave, Brown Dolomite, Granite Wash and fractured Granite formations at depths no greater than 3,500 feet. The Company's gas in the West Panhandle field has an average energy content of 1,300 Btu per Mcf and is produced from approximately 600 wells on more than 241,000 acres covering over 375 square miles. The Company's wellhead gas produced from the West Panhandle field contains a high quantity of NGLs, yielding relatively greater NGL volumes than realized from the Company's 1,025 Btu per Mcf content wellhead gas in its Hugoton field. The Company controls the wells, production equipment, gathering system and gas processing plant for the field.

During the year ended December 31, 2003, the Company placed 71 new development wells on production, drilled four development wells that were plugged and abandoned due to noncommerciality and had 24 development wells and two extension wells in progress at December 31, 2003. The Company plans to drill approximately 111 wells in the West Panhandle field during 2004.

Gulf of Mexico area. In the Gulf of Mexico, the Company is focused on reserve and production growth through a portfolio of shelf and deepwater development projects, high-impact, higher-risk deepwater exploration drilling, shelf exploration drilling and exploitation opportunities inherent in the properties the Company currently has producing on the shelf. To accomplish this, the Company has devoted most of its domestic exploration efforts to the Gulf of Mexico shelf and deepwater as well as investments in and utilization of 3-D seismic technology. During the year ended December 31, 2003, the Company successfully drilled three exploratory wells in the deepwater Gulf of Mexico and one successful development well on the shelf. The Company also drilled four exploratory dry holes on the shelf and two exploratory dry holes in the deepwater Gulf of Mexico during 2003 and had four exploratory wells in the deepwater Gulf of Mexico and one exploratory well on the shelf in progress as of December 31, 2003.

In the deepwater Gulf of Mexico, the Company has three major projects, two of which are now on production and one that was in progress at December 31, 2003:

- Canyon Express - The Canyon Express development project is a joint development of three deepwater Gulf of Mexico gas discoveries, including the Company's TotalFinaElf-operated Aconcagua and Marathon-operated Camden Hills fields, where the Company holds 37.5 percent and 33.3 percent working interests, respectively. The Company participated in the discovery of the Aconcagua gas field in 1999 during the early stages of building its exploration program, and later added Camden Hills to its portfolio to enhance its ownership in the project. The Canyon Express project was approved for development in June 2000 and reached first production in September 2002. The Canyon Express gathering system is the first in the area and provides the Company and its partners with the opportunity to collect gathering and handling revenues from the use of the system by any future discoveries in the area. The Company has plans to drill and complete an additional development well at Aconcagua during 2004.

- Falcon Area - The Company-operated Falcon two-well field was completed ahead of schedule and placed on production in March 2003. During the first quarter of 2003, the Company drilled its Harrier discovery, along with two exploratory dry holes. The Company also acquired the remaining 25 percent working interest in the Falcon field, Harrier discovery and surrounding prospects that it did not already own in March 2003. In addition, during the third quarter of 2003, the Company successfully drilled the Tomahawk and Raptor prospects. All three discoveries, Harrier, Tomahawk and Raptor, will be developed as single-well subsea tie-backs to the Falcon field facilities which were designed to be expandable. To accommodate this incremental production and potential throughput associated with additional planned exploration, an additional parallel pipeline connecting the Falcon field to the Falcon platform on the Gulf of Mexico shelf has been added, doubling its capacity to 400 MMcf of gas per day. The Company placed the Harrier field on production in early January 2004 and plans to place Tomahawk and Raptor on production in mid-2004. In addition to the development operations discussed above, the Company has budgeted to drill up to three additional Falcon area prospects in 2004.

- Devils Tower - The Dominion-operated Devils Tower development project was sanctioned in 2001 as a spar development project with the owners leasing a spar from a third party for the life of the field. The hull of the spar was constructed in Indonesia and was successfully transported to the United States during the first quarter of 2003 where the topsides were added in the fourth quarter of 2003. The spar has slots for eight dry tree wells and up to two subsea tie-back risers and is capable of handling 60 MBbls of oil per day and 60 MMcf of gas per day. Eight Devils Tower wells and one subsea tie-back well, the Triton field, have been drilled and are awaiting completion. In addition, the Company has drilled an appraisal well at Triton that was successful subsequent to year-end and an exploration well is in progress on its Goldfinger prospect. Devils Tower production is expected to begin in mid-2004 and will be phased in as the wells are individually completed from the spar. The Company holds a 25 percent working interest in each of the above projects.

During 2002, the Company also participated in the Marathon-operated deepwater Gulf of Mexico Ozona Deep discovery. The Company is currently negotiating a tie-back agreement to an existing facility in the area, the economics of which will determine future activities. In late 2003, the Company spudded an exploratory well on the BP-operated Juno prospect with a 25 percent working interest and an exploratory well on the Unocal-operated Myrtle Beach prospect with a 10 percent working interest, each of which remains in progress with results expected to be known in February 2004. The Company also plans to spud an exploratory well on the Dominion-operated Thunder Hawk prospect during 2004. The Company has a 12.5 percent working interest in Thunder Hawk.

During January 2003, the Company announced a joint exploration agreement with Woodside Energy (USA), Inc. ("Woodside"), a subsidiary of Woodside Energy Ltd. of Australia, for a two-year drilling program over the shallow-water Texas shelf region of the Gulf of Mexico. Under the agreement, Woodside acquired a 50 percent working interest in 47 offshore exploration blocks operated by the Company. The agreement covers eight prospects and 19 leads and included five exploratory wells to be drilled in 2003 and three in 2004. Most of the wells to be drilled under the agreement will target gas plays below 15,000 feet. The first three wells under this joint agreement were unsuccessful. The fourth well, Midway, subsequent to December 31, 2003 encountered 30 feet of net gas pay and is expected to be tied back to an existing production platform with first production anticipated during the second half of 2004. Three other intervals with an additional 60 feet of gas bearing sands were also encountered and will require additional analysis to determine future commercial potential. The Company has a 37.5 percent working interest in this well. The fifth well to be drilled in 2003 and the three wells scheduled for 2004 under the agreement, which has been extended for one additional year, were mutually agreed to be deferred until more technical work can be performed on the prospects by both companies. Additionally, the Company and Woodside are evaluating shallower gas prospects on the Gulf of Mexico shelf for possible inclusion in the 2004 drilling program.

Onshore Gulf Coast area. The Company has focused its drilling efforts in this area on the Pawnee field in the Edwards Reef trend in South Texas. The Company placed five development wells and one extension well on production at Pawnee during 2003, had two wells in progress at year-end and plans to drill approximately ten wells in 2004.

Alaska area. During the fourth quarter of 2002, the Company acquired a 70 percent working interest and operatorship in ten state leases on Alaska's North Slope. Associated therewith, the Company drilled three exploratory wells during the first quarter of 2003 to test a possible extension of the productive sands in the Kuparuk River field into the shallow waters offshore. Although all three of the wells found the sands filled with oil, they were too thin to be considered commercial on a stand-alone basis. However, the wells also encountered thick sections of oil-bearing Jurassic-aged sands, and the first well flowed at a sustained rate of approximately 1,300 barrels per day. The test results are continuing to be evaluated to determine the commercial viability of the Jurassic reservoir. Subsequent to year-end, the Company farmed-into a large acreage block to the southwest of the Company's discovery. During 2004, the Company plans to evaluate seismic data over the area to the southwest of its discovery, analyze results from other wells drilled in the area and determine the location of future exploration wells to further test the discovery.

In addition, the Company was the high bidder on 53 tracts covering an additional 159,000 acres on the North Slope in the most recent state lease sale, establishing a leasehold over a variety of prospects. The Company has opened an office in Anchorage and is putting together a team of employees that will focus their efforts on enhancing the Company's position in Alaska.

International. The Company's international operations are located in the Neuquen and Austral Basins areas of Argentina, the Chinchaga, Martin Creek and Lookout Butte areas of Canada, the Sable oil field offshore South Africa and in southern Tunisia. Additionally, the Company has other significant oil development and exploration activities in the shallow waters offshore Gabon, gas exploration activities in the shallow waters offshore South Africa and oil development and exploration activities in Tunisia. As of December 31, 2003, approximately 16 percent, two percent and three percent of the Company's proved reserves are located in Argentina, Canada and Africa, respectively.

Argentina. The Company's share of Argentine production during the year ended December 31, 2003 averaged 25.7 MBOE per day, or approximately 17 percent of the Company's equivalent production. The Company's operated production in Argentina is concentrated in the Neuquen Basin which is located about 925 miles southwest of Buenos Aires and to the east of the Andes Mountains. Oil and gas are produced primarily from the Al Norte de la Dorsal, the Al Sur de la Dorsal, the Dadin, the Loma Negra, the Dos Hermanas, the Anticlinal Campamento and the Estacion Fernandez Oro blocks, in each of which the Company has a 100 percent working interest. Most of the gas produced from these blocks is processed in the Company's Loma Negra gas processing plant. The Company also operates and has a 50 percent working interest in the Lago Fuego field which is located in Tierra del Fuego, an island in the extreme southern portion of Argentina, approximately 1,500 miles south of Buenos Aires.

Most of the Company's non-operated production in Argentina is located in Tierra del Fuego where oil, gas and NGLs are produced from six separate fields in which the Company has a 35 percent working interest. The Company also has a 14.4 percent working interest in the Confluencia field which is located in the Neuquen Basin.

During the year ended December 31, 2003, the Company expended $52.1 million on Argentine development, exploration and acquisition activities. The Company drilled 31 development wells and 30 extension/exploratory wells, of which 29 development wells and 21 extension/exploratory wells were successful. Also during 2003, the Company acquired an additional 150,000 acres in the Ojo de Agua, Cutral Co Sur and Collun Cura blocks in the Neuquen Basin and shot seismic covering approximately 258,000 acres. The Company plans to be more active in Argentina in 2004 with approximately $113 million budgeted for oil and gas development and exploration opportunities.

Canada. The Company's Canadian producing properties are located primarily in Alberta and British Columbia, Canada. Production during the year ended December 31, 2003 averaged 8.0 MBOE per day, or approximately five percent of the Company's equivalent production. The Company continues to focus its development, exploration and acquisition activities in the core areas of northeast British Columbia and southwest Alberta. The Canadian assets are geographically concentrated, predominantly shallow gas and more than 95 percent operated by the Company in the following areas: Chinchaga, Martin Creek and Lookout Butte.

Production from the Chinchaga area in northeast British Columbia is relatively dry gas from formation depths averaging 3,400 feet. In the Martin Creek area of British Columbia, production is relatively dry gas from various reservoirs ranging from 3,700 feet to 4,300 feet. The Lookout Butte area in southwest Alberta produces gas and condensate from the Mississippian Turner Valley formation at approximately 12,000 feet.

During the year ended December 31, 2003, the Company expended $53.0 million on Canadian exploration, development, and acquisition activities. The Company drilled 14 development wells and 42 exploratory/extension wells, primarily in the Chinchaga and Martin Creek areas, of which seven development wells and 16 exploratory/extension wells were successful. Most of these wells were drilled during the first quarter of 2003 as these areas are only accessible for drilling during the winter months. The Company plans to spend approximately $31 million on oil and gas development and exploration opportunities in Canada during 2004.

Africa. In Africa, the Company has entered into agreements to explore for oil and gas in South Africa, Gabon and Tunisia. The amended South African agreements cover over five million acres along the southern coast of South Africa, generally in water depths less than 650 feet. The Gabon agreement covers 313,937 acres off the coast of Gabon, generally in water depths less than 100 feet. The Tunisian agreements can be separated into two categories: the first includes three permits covering 2.9 million acres onshore southern Tunisia which the Company operates with a 50 percent working interest and the second includes the Anadarko-operated Anaguid permit covering 1.2 million acres onshore southern Tunisia in which the Company has a 38.7 percent working interest and the AGIP-operated Adam concession and Borj El Khadra permit covering 212,420 acres and 969,755 acres, respectively, onshore southern Tunisia in which the Company has a 28 percent and 40 percent working interest, respectively. During the year ended December 31, 2003, the Company expended $52.9 million of acquisition, development and exploration drilling and seismic capital in South Africa, Gabon and Tunisia.

South Africa. In South Africa, the Company spent $32.8 million of capital to complete its Petro SA-operated Sable development project and to drill three exploratory wells that were dry holes. The Sable oil field began producing in August 2003. The Company has a 40% working interest in the Sable field. In 2004, the Company currently plans to spend approximately $9 million in South Africa for production enhancement opportunities at Sable and for an exploration well late in the year.

Gabon. In Gabon, the Company spent $4.4 million of development and seismic capital to further evaluate its Bigorneau South discovery, located offshore in the Southern Gabon Basin on its Olowi permit. Pioneer is the operator of the permit with a 100 percent working interest. To date, the Company has drilled four successful offshore wells which have established significant oil in place. The Company recently received ministerial approval for improved terms associated with the Olowi permit. Subsequent to year-end, the Company has commenced a multi-well drilling program to further define the scale of a development plan, initially focusing on the Lower Gamba, and to test a new exploratory prospect. The Company is also soliciting bids from possible new partners in the project.

Tunisia. In Tunisia, the Company spent $15.6 million of acquisition, drilling and seismic capital during the year ended December 31, 2003 primarily to drill one successful development well in its Adam concession, one successful exploratory well in its AGIP-operated Hawa oil field and one exploratory well that was a dry hole in its Company-operated Jorf permit. The Hawa oil field started production in January 2004. In addition, the Company also drilled two exploratory wells on its Anadarko-operated Anaguid permit that remain in progress as of December 31, 2003. The Company also completed the construction of a 15 kilometer flowline from the Adam discovery to an AGIP-operated facility, allowing production to begin in May 2003. The capital budget of approximately $14 million for Tunisia in 2004 includes an exploration well and development well in the Adam concession, two exploration wells on the Company-operated El Hamra permit and two appraisal wells on the Anaguid permit.

Selected Oil and Gas Information

The following tables set forth selected oil and gas information for the Company as of and for each of the years ended December 31, 2003, 2002 and 2001. Because of normal production declines, increased or decreased drilling activities and the effects of past and future acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

Production, price and cost data. The following table sets forth production, price and cost data with respect to the Company's properties for the years ended December 31, 2003, 2002 and 2001:

PRODUCTION, PRICE AND COST DATA (a)

	Year Ended December 31,												
	2003					2002				2001			
	United States	Argentina	Canada	Africa	Total	United States	Argentina	Canada	Total	United States	Argentina	Canada	Total
Production information:													
Annual production:													
Oil (MBbls)	8,952	3,171	40	723	12,886	8,555	2,914	45	11,514	8,629	3,566	303	12,498
NGLs (MBbls)	7,423	481	331	-	8,235	7,487	254	345	8,086	7,232	200	368	7,800
Gas (MMcf)	162,647	34,357	15,209	-	212,213	84,811	28,551	17,653	131,015	77,609	31,830	18,426	127,865
Total (MBOE)	43,483	9,378	2,906	723	56,490	30,177	7,926	3,333	41,436	28,796	9,071	3,742	41,609
Average daily production:													
Oil (Bbls)	24,525	8,687	111	1,981	35,304	23,437	7,984	124	31,545	23,641	9,769	831	34,241
NGLs (Bbls)	20,338	1,318	906	-	22,562	20,512	696	946	22,154	19,815	547	1,008	21,370
Gas (Mcf)	445,609	94,128	41,669	-	581,406	232,360	78,220	48,365	358,945	212,629	87,204	50,481	350,314
Total (BOE)	119,129	25,694	7,962	1,981	154,766	82,677	21,716	9,131	113,524	78,893	24,851	10,253	113,997
Average prices, including hedge results:													
Oil (per Bbl)	$ 25.25	$ 25.62	$ 29.10	$ 29.52	$ 25.59	$ 23.66	$ 20.63	$ 22.26	$ 22.89	$ 24.34	$ 23.79	$ 21.87	$ 24.12
NGLs (per Bbl)	$ 19.04	$ 22.85	$ 24.80	$ -	$ 19.50	$ 13.77	$ 14.56	$ 16.77	$ 13.92	$ 16.88	$ 19.29	$ 21.11	$ 17.14
Gas (per Mcf)	$ 4.49	$ .56	$ 3.90	$ -	$ 3.81	$ 3.16	$ .48	$ 2.50	$ 2.49	$ 4.10	$ 1.31	$ 2.86	$ 3.23
Revenue (per BOE)	$ 25.24	$ 11.87	$ 23.61	$ 29.52	$ 22.99	$ 19.00	$ 9.79	$ 15.27	$ 16.94	$ 22.56	$ 14.36	$ 17.94	$ 20.36
Average prices, excluding hedge results:													
Oil (per Bbl)	$ 29.58	$ 26.31	$ 29.10	$ 30.07	$ 28.80	$ 23.85	$ 20.33	$ 22.26	$ 22.95	$ 24.56	$ 22.40	$ 21.87	$ 23.88
NGLs (per Bbl)	$ 19.04	$ 22.85	$ 24.80	$ -	$ 19.50	$ 13.77	$ 14.56	$ 16.77	$ 13.92	$ 16.88	$ 19.29	$ 21.11	$ 17.14
Gas (per Mcf)	$ 4.93	$ .56	$ 4.26	$ -	$ 4.17	$ 3.02	$ .48	$ 2.40	$ 2.38	$ 3.96	$ 1.31	$ 3.27	$ 3.20
Revenue (per BOE)	$ 25.71	$ 12.10	$ 25.54	$ 30.07	$ 25.07	$ 18.65	$ 9.68	$ 14.77	$ 16.63	$ 22.26	$ 13.81	$ 19.95	$ 20.21
Average costs (per BOE):													
Production costs:													
Lease operating	$ 3.10	$ 2.57	$ 4.06	$ 3.87	$ 3.07	$ 3.21	$ 1.61	$ 2.64	$ 2.87	$ 2.76	$ 2.64	$ 3.01	$ 2.76
Taxes:													
Production	.76	.20	-	.12	.62	.71	.13	-	.54	.98	.28	-	.74
Ad valorem	.51	-	-	-	.40	.75	-	-	.54	.71	-	-	.49
Field fuel	.94	-	-	-	.72	.85	-	-	.62	1.27	-	-	.88
Workover	.15	.01	.43	-	.14	.28	.01	.59	.25	.20	.01	.32	.17
Total	$ 5.46	$ 2.78	$ 4.49	$ 3.99	$ 4.95	$ 5.80	$ 1.75	$ 3.23	$ 4.82	$ 5.92	$ 2.93	$ 3.33	$ 5.04
Depletion expense	$ 6.85	$ 4.96	$ 9.98	$ 10.69	$ 6.75	$ 4.64	$ 5.00	$ 8.36	$ 5.01	$ 4.46	$ 5.67	$ 7.71	$ 5.02

(a) These amounts represent the Company's historical results from operations without making pro forma adjustments for any acquisitions, divestitures or drilling activity that occurred during the respective years.

Productive wells. The following table sets forth the number of productive oil and gas wells attributable to the Company's properties as of December 31, 2003, 2002 and 2001:

PRODUCTIVE WELLS (a)

	Gross Productive Wells			Net Productive Wells		
	Oil	Gas	Total	Oil	Gas	Total
As of December 31, 2003:						
United States	3,691	2,012	5,703	2,978	1,907	4,885
Argentina	669	194	863	539	141	680
Canada	4	268	272	4	210	214
Africa	8	-	8	3	-	3
Total	4,372	2,474	6,846	3,524	2,258	5,782
As of December 31, 2002:						
United States	3,448	1,952	5,400	2,745	1,855	4,600
Argentina	694	208	902	534	142	676
Canada	1	246	247	1	197	198
Africa	5	-	5	2	-	2
Total	4,148	2,406	6,554	3,282	2,194	5,476
As of December 31, 2001:						
United States	3,485	1,931	5,416	2,116	1,613	3,729
Argentina	669	162	831	454	132	586
Canada	4	299	303	3	240	243
Total	4,158	2,392	6,550	2,573	1,985	4,558

(a) Productive wells consist of producing wells and wells capable of production, including shut-in wells. One or more completions in the same well bore are counted as one well. Any well in which one of the multiple completions is an oil completion is classified as an oil well. As of December 31, 2003, the Company owned interests in 132 gross wells containing multiple completions.

Leasehold acreage. The following table sets forth information about the Company's developed, undeveloped and royalty leasehold acreage as of December 31, 2003:

LEASEHOLD ACREAGE

	Developed Acreage		Undeveloped Acreage		Royalty
	Gross Acres	Net Acres	Gross Acres	Net Acres	Acreage
As of December 31, 2003:					
United States:					
Onshore	1,011,370	869,974	125,095	79,224	229,650
Offshore	120,333	58,838	828,311	562,604	10,500
	1,131,703	928,812	953,406	641,828	240,150
Argentina	713,000	319,000	1,154,000	1,094,000	-
Canada	161,000	123,000	431,000	310,000	15,000
Africa	222,020	63,318	10,778,415	6,109,136	-
Total	2,227,723	1,434,130	13,316,821	8,154,964	255,150

Drilling activities. The following table sets forth the number of gross and net productive and dry wells in which the Company had an interest that were drilled during the years ended December 31, 2003, 2002 and 2001. This information should not be considered indicative of future performance, nor should it be assumed that there was any correlation between the number of productive wells drilled and the oil and gas reserves generated thereby or the costs to the Company of productive wells compared to the costs of dry holes.

DRILLING ACTIVITIES

	Gross Wells Year Ended December 31,			Net Wells Year Ended December 31,		
	2003	2002	2001	2003	2002	2001
United States:						
Productive wells:						
Development	244	148	228	210.5	83.0	114.6
Exploratory	4	6	20	4.0	2.0	11.0
Dry holes:						
Development	6	4	15	6.0	3.7	14.6
Exploratory	6	3	8	3.6	2.1	5.1
	260	161	271	224.1	90.8	145.3
Argentina:						
Productive wells:						
Development	29	13	19	29.0	13.0	17.7
Exploratory	21	9	26	21.0	9.0	25.5
Dry holes:						
Development	2	1	1	2.0	1.0	1.0
Exploratory	9	8	16	9.0	8.0	14.0
	61	31	62	61.0	31.0	58.2
Canada:						
Productive wells:						
Development	7	13	24	7.0	10.4	20.3
Exploratory	16	9	12	14.9	9.0	10.2
Dry holes:						
Development	7	4	2	6.5	4.0	2.0
Exploratory	26	3	13	21.1	3.0	11.8
	56	29	51	49.5	26.4	44.3
Africa:						
Productive wells:						
Development	1	4	-	.3	1.6	-
Exploratory	1	4	3	.4	3.4	2.4
Dry holes:						
Development	-	-	-	-	-	-
Exploratory	4	-	3	3.5	-	1.9
	6	8	6	4.2	5.0	4.3
Total	383	229	390	338.8	153.2	252.1
Success ratio (a)	84%	90%	85%	85%	86%	80%

(a) Represents the ratio of those wells that were successfully completed as producing wells or wells capable of producing to total wells drilled and evaluated.

The following table sets forth information about the Company's wells upon which drilling was in progress as of December 31, 2003:

	Gross Wells	Net Wells
United States:		
Development	28	27.1
Exploratory	11	5.8
	39	32.9
Argentina:		
Development	3	3.0
Exploratory	10	10.0
	13	13.0
Canada:		
Development	6	5.6
Exploratory	11	10.1
	17	15.7
Africa:		
Development	-	-
Exploratory	2	.8
	2	.8
Total	71	62.4

ITEM 3. LEGAL PROCEEDINGS

The Company is party to various legal proceedings, which are described under "Legal actions" in Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data". The Company is also party to other litigation incidental to its business. Except for the specific legal actions described in Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplemental Data", the Company believes that the probable damages from such other legal actions will not be in excess of 10 percent of the Company's current assets.

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

The Company did not submit any matters to a vote of security holders during the fourth quarter of 2003.

PART II

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

The Company's common stock is listed and traded on the New York Stock Exchange under the symbol "PXD". The following table sets forth, for the periods indicated, the high and low sales prices for the Company's common stock, as reported in the New York Stock Exchange composite transactions. The Company's board of directors did not declare dividends to the holders of the Company's common stock during the years ended December 31, 2003 or 2002. See "2004 Outlook" included in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" for discussion related to future dividends.

The following table sets forth quarterly high and low prices of the Company's common stock for the years ended December 31, 2003 and 2002.

	High	Low
Year ended December 31, 2003:		
Fourth quarter	$ 32.90	$ 25.00
Third quarter	$ 26.52	$ 22.76
Second quarter	$ 28.44	$ 22.85
First quarter	$ 27.44	$ 23.27
Year ended December 31, 2002:		
Fourth quarter	$ 27.50	$ 21.70
Third quarter	$ 26.23	$ 19.50
Second quarter	$ 26.05	$ 20.00
First quarter	$ 22.30	$ 16.10

On January 30, 2004, the last reported sales price of the Company's common stock, as reported in the New York Stock Exchange composite transactions, was $31.92 per share.

As of January 30, 2004, the Company's common stock was held by approximately 29,118 holders of record.

Securities Authorized for Issuance under Equity Compensation Plans

The following table summarizes information about the Company's equity compensation plans as of December 31, 2003:

	(a) Number of securities to be issued upon exercise of outstanding options	Weighted average exercise price of outstanding options	(b) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in first column)
Equity compensation plans approved by security holders (c):			
Pioneer Natural Resources Company:			
Long-Term Incentive Plan	4,857,064	$ 19.63	6,305,591
Employee Stock Purchase Plan	-	$ -	589,884
Predecessor plans	417,052	$ 25.95	-
	5,274,116		6,895,475

(a) There are no outstanding warrants or equity rights awarded under the Company's equity compensation plans.

(b) The Company's Long-Term Incentive Plan provides for the issuance of a maximum number of shares of common stock equal to 10 percent of the total number of shares of common stock equivalents outstanding less the total number of shares of common stock subject to outstanding awards under any stock-based plan for the directors, officers or employees of the Company. The number of remaining securities available for future issuance under the Company's Employee Stock Purchase Plan is based on the original authorized issuance of 750,000 shares less 160,116 cumulative shares issued through December 31, 2003. See Note G of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of each of the Company's equity compensation plans.

(c) There are no equity compensation plans that have not been approved by security holders.

ITEM 6. SELECTED FINANCIAL DATA

The following selected consolidated financial data as of and for each of the five years ended December 31, 2003 for the Company should be read in conjunction with "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 millions, except per share data)				
Statement of Operations Data:					
Revenues and other income:					
Oil and gas	$ 1,298.6	$ 701.8	$ 847.0	$ 852.7	$ 644.6
Interest and other (a)	12.3	11.2	21.8	25.8	89.7
Gain (loss) on disposition of assets, net	1.3	4.4	7.7	34.2	(24.2)
Total revenues and other income	1,312.2	717.4	876.5	912.7	710.1
Costs and expenses:					
Oil and gas production	279.5	199.6	209.7	189.3	159.5
Depletion, depreciation and amortization	390.8	216.4	222.6	214.9	236.1
Impairment of properties and facilities	-	-	-	-	17.9
Exploration and abandonments	132.8	85.9	127.9	87.5	66.0
General and administrative	60.5	48.4	37.0	33.3	40.2
Reorganization	-	-	-	-	8.5
Accretion of discount on asset retirement obligations	5.0	-	-	-	-
Interest	91.4	95.8	131.9	162.0	170.3
Other (b)	21.4	39.5	43.4	79.5	34.7
Total costs and expenses	981.4	685.6	772.5	766.5	733.2
Income (loss) before income taxes and cumulative effect of change in accounting principle	330.8	31.8	104.0	146.2	(23.1)
Income tax benefit (provision) (c)	64.4	(5.1)	(4.0)	6.0	.6
Income (loss) before cumulative effect of change in accounting principle	395.2	26.7	100.0	152.2	(22.5)
Cumulative effect of change in accounting principle, net of tax (d)	15.4	-	-	-	-
Net income (loss)	$ 410.6	$ 26.7	$ 100.0	$ 152.2	$ (22.5)
Income (loss) before cumulative effect of change in accounting principle per share:					
Basic	$ 3.37	$ .24	$ 1.01	$ 1.53	$ (.22)
Diluted	$ 3.33	$ .23	$ 1.00	$ 1.53	$ (.22)
Net income (loss) per share:					
Basic	$ 3.50	$ .24	$ 1.01	$ 1.53	$ (.22)
Diluted	$ 3.46	$ .23	$ 1.00	$ 1.53	$ (.22)
Weighted average shares outstanding:					
Basic	117.2	112.5	98.5	99.4	100.3
Diluted	118.5	114.3	99.7	99.8	100.3
Balance Sheet Data (as of December 31):					
Total assets	$ 3,951.6	$ 3,455.1	$ 3,271.1	$ 2,954.4	$ 2,929.5
Long-term liabilities	$ 1,749.9	$ 1,796.9	$ 1,743.7	$ 1,804.5	$ 1,914.5
Total stockholders' equity	$ 1,759.8	$ 1,374.9	$ 1,285.4	$ 904.9	$ 774.6

(a) 1999 includes $41.8 million of option fees and liquidated damages and $30.2 million of income associated with an excise tax refund.

(b) Other expense for 2003, 2002, 2001 and 2000 include losses on the early extinguishment of debt of $1.5 million, $22.3 million, $3.8 million and $12.3 million, respectively. Other expense for 2000 and 1999 include noncash mark-to-market charges for changes in the fair values of non-hedge financial instruments of $58.5 million and $27.0 million, respectively. See Note O of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".

(c) The Company's income tax benefit for 2003 includes a $197.7 million adjustment to reduce United Sates deferred tax asset valuation allowances. See Note P of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".

(d) The Company's cumulative effect of change in accounting principle relates to the adoption of SFAS No. 143. See Notes B and L of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".

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

2003 Highlights

Pioneer's financial and operating results for the year ended December 31, 2003 included the following highlights:

- Production volumes increased 36 percent in 2003 as compared to 2002, principally due to the completion of the Canyon Express, Falcon and Sable development projects.

- Oil and gas revenue increased 85 percent in 2003 as a result of the increased production volumes and increases in North American gas and worldwide oil prices.

- Pre-tax income increased to $330.8 million from $31.8 million in 2002.

- Pioneer's solid progress towards its strategic objectives over the past four years and improving key economic indicators, together with other relevant factors and associated evaluations, led the Company to reverse its allowances against United States deferred tax assets during 2003. The reversal of the allowances against United States deferred tax assets resulted in the recognition of a deferred tax benefit of $197.7 million during 2003 of which $104.7 million was reversed in the third quarter of 2003 (see Note P of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the reversal of the allowances against the Company's United States deferred tax assets).

- Net cash provided by operating activities increased 130 percent to $763.7 million in 2003 as compared to $332.2 million in 2002.

- The Company replaced its $575 million revolving credit facility with a new five-year $700 million revolving credit agreement with terms similar to investment grade companies.

- The Company participated in exploration discoveries in the Harrier, Tomahawk and Raptor fields in the deepwater Gulf of Mexico and the Hawa field in Tunisia.

- The Company completed a strategic acquisition of the remaining 25 percent working interest that the Company did not already own in the Falcon field, Harrier field and surrounding satellite prospects.

- The Company was the high bidder on 53 tracts covering an additional 159,000 acres on the Alaskan North Slope.

- The Company succeeded in obtaining ministerial approval for improved terms associated with the Olowi permit in Gabon and booked 16.6 MMBOE of proved reserves in Gabon during 2003.

- The Company's successful capital investment programs resulted in the replacement of 193 percent and 216 percent of production during the one- and three-year periods ended December 31, 2003, respectively, resulting in total proved reserves of 789.1 MMBOE at December 31, 2003.

- The Company reported acquisition and finding costs per BOE of $6.64 and $6.76 during the one- and three-year periods ended December 31, 2003, respectively.

2003 Financial and Operating Performance

During the years ended December 31, 2003, 2002 and 2001, the Company recorded net income of $410.6 million, $26.7 million and $100.0 million ($3.46, $.23 and $1.00 per diluted share), respectively. Compared to 2002, the Company's 2003 total revenues and other income increased by $594.8 million, or 83 percent, including a $596.9 million increase in oil and gas revenues. The increase in oil and gas revenues was due to increases in production volumes and increases of 12 percent, 40 percent and 53 percent in average oil, NGL and gas prices, respectively, including the effects of commodity price hedges.

Compared to 2002, the Company's total costs and expenses increased by $295.8 million, or 43 percent, during the year ended December 31, 2003. The increase in total costs and expenses was primarily reflective of a $46.9 million increase in exploration and abandonments expense, primarily due to increased exploration/extension drilling in the Gulf of Mexico, Argentina, Canada and South Africa, a $174.5 million increase in depletion, depreciation and amortization expense, primarily driven by increases in depletion associated with increased production volumes from higher-cost-basis Gulf of Mexico and South Africa properties and an $80.0 million increase in oil and gas production costs, which primarily resulted from increases in production volumes, the strengthening of both the Argentine peso and Canadian dollar and commodity prices that impacted variable lease operating expenses and production taxes, partially offset by an $18.3 million decrease in other expense, primarily due to $22.3 million of losses recognized during 2002 associated with debt extinguished prior to its stated maturity.

During the year ended December 31, 2003, the Company's net cash provided by operating activities increased to $763.7 million, as compared to $332.2 million during 2002 and $475.6 million during 2001. The increase in net cash provided by operating activities during 2003 was primarily due to increases in oil, NGL and gas production volumes and prices, as discussed above.

During the year ended December 31, 2003, successful capital investment activities increased the Company's proved reserves to 789.1 MMBOE, reflecting the effects of strategic acquisitions of properties in the Company's core operating areas and a successful drilling program which resulted in the replacement of 193 percent of production at an acquisition and finding cost per BOE of $6.64. During the three years ended December 31, 2003, Pioneer has replaced 216 percent of production at an acquisition and finding cost per BOE of $6.76. Costs incurred for the year ended December 31, 2003 totaled $723.0 million, including $151.0 million of proved and unproved property acquisitions and $572.0 million of exploration and development drilling and seismic expenditures.

See "Results of Operations" and "Capital Commitments, Capital Resources and Liquidity", below, for more in-depth discussions of the Company's oil and gas producing activities, including discussions pertaining to oil and gas production volumes, prices, hedging activities, costs and expenses, capital commitments, capital resources and liquidity.

2004 Outlook

Commodity prices. World oil prices increased during the year ended December 31, 2003 in response to political unrest and supply disruptions in the Middle East as well as other supply and demand factors. North American gas prices also increased during 2003 in response to continued strong supply and demand fundamentals. The Company's outlook for 2004 commodity prices is cautiously optimistic. Significant factors that will impact 2004 commodity prices include developments in Iraq and other Middle East countries, the extent to which members of OPEC and other oil exporting nations are able to manage oil supply through export quotas and variations in key North American gas supply and demand indicators. Pioneer will continue to strategically hedge oil and gas price risk to mitigate the impact of price volatility on its oil, NGL and gas revenues.

As of December 31, 2003, the Company had hedged 18,973 barrels per day of 2004 oil production under swap contracts with a weighted average fixed price to be received of $25.84 per Bbl. The Company had also hedged 283,962 Mcf per day of 2004 gas production under swap contracts with a weighted average fixed price to be received of $4.16 per MMBtu. During January 2004, the Company increased its 2004 commodity hedge positions by entering into 32,967 Mcf per day of first quarter gas swap contracts with average per MMBtu fixed prices of $7.11. Additionally, at December 31, 2003 the Company had net deferred gains on terminated oil hedge contracts of $1.0 million that will be recognized as increases to oil revenue during 2004 and $42.9 million of net deferred gains on terminated gas hedge contracts that will be recognized as increases to gas revenue during 2004. See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's commodity hedge positions at December 31, 2003. Also see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for disclosures about the Company's commodity related derivative financial instruments.

Capital expenditures. During 2004, the Company's budget for oil and gas capital activities is expected to range from $550 million to $600 million, of which approximately 65 percent has been budgeted for development drilling and facility costs and 35 percent for exploration expenditures. The Company's 2004 capital budget is allocated approximately 70 percent to the United States, 19 percent to Argentina and the remaining 11 percent is budgeted for expenditures in Canada, Gabon, Tunisia, South Africa and other foreign areas. Pioneer expects to drill approximately 400 exploration and development wells during 2004. During 2004 and 2005, the Company expects to expend approximately $219 million and $348 million, respectively, of capital for development drilling and facility costs related to its proved undeveloped reserves.

Production growth. The Company expects that its annual 2004 worldwide production will range from 65 MMBOE to 73 MMBOE, or approximately 178 MBOE to 200 MBOE per day, an increase of 15 percent to 29 percent over 2003 levels. The bottom end of the range includes a full year of production from the Company's deepwater Gulf of Mexico Falcon and Harrier gas fields, the Sable oil field in South Africa and the Hawa field in Tunisia, coupled with increases in production from the Company's 2004 capital program and the inherent variability in production results. The Company expects, based on quoted futures prices, to generate cash flow significantly in excess of its capital program and has considered the potential to invest a portion of the excess cash for additional development drilling or core area acquisitions in arriving at the top end of the 2004 production range.

The outlook for continued production growth in 2005 is strong considering that first production from several new projects is not expected until well into 2004. The Company will have its first full year of production from the Devils Tower, Tomahawk and Raptor deepwater fields during 2005, and the Company believes it has sufficient development inventory to support production growth in the United States, Argentina, Canada and Tunisia. As a result, Pioneer currently expects production in 2005 to match 2004 at a minimum, with considerable upside given the potential investment of excess cash flow to develop new exploration successes and/or acquire additional assets in core areas during 2004 and 2005.

Longer term, with several discoveries to develop for 2006 and beyond, a pipeline of exploration opportunities, potential for continued core area acquisitions, continuing strong commodity prices and significant excess cash flow, Pioneer has targeted five-year average compounded annual production growth of ten percent.

Costs and expenses. The Company expects that its costs and expenses that are highly correlated with production volumes, such as production costs and depletion expense, will increase in absolute amounts during 2004. Additionally, the Company expects that depletion expense will increase on a per BOE basis during 2004 as compared to 2003 due to new production from Harrier, Tomahawk, Raptor and Devils Tower fields in the deepwater Gulf of Mexico and increased production from the Sable oil field offshore South Africa. The per BOE cost bases of these fields are higher than that of Pioneer's average producing property in 2003. Additionally, the average per BOE lifting costs of Devils Tower and Sable oil field production are expected to exceed the Company's average 2003 per BOE lifting costs. The Company expects average per BOE production taxes to decline during 2004 as compared to 2003 as the production from the aforementioned properties are not burdened by such taxes. Ad valorem taxes are highly correlated with prior year commodity prices. As a consequence of increases in oil, NGL and gas prices during 2003, ad valorem taxes are expected to be higher in 2004, as compared to 2003. The Company anticipates an increase in general and administrative expenses during 2004 due to additional staffing and the amortization of restricted stock that is being awarded to officers and employees in lieu of stock options, which were awarded in prior years.

Capital allocation. Four years ago, the Company made a commitment to move its financial position to investment grade standards, and significant improvement has been accomplished during that period with year-end 2003 debt to book capitalization reaching 46.9 percent as compared to 69.3 percent at the end of 1999. The Company has established a targeted range for debt to book capitalization of 37 percent to 43 percent. Given the expanding financial strength of the Company and expectations for significant cash flow in excess of its capital budget, the Company expects to use a portion of its excess cash flow in 2004 to further reduce long-term debt by a minimum of $100 million. Additionally, the Company' s Board of Directors have approved a plan to begin a dividend program of $.20 per common share, payable in two semi-annual installments of $.10 per common share, beginning in 2004.

During 2004 through 2006, the Company anticipates, based upon year-end futures prices, that it will have significant excess cash flow even after funding its typical annual capital budgets, planned dividends and achieving its leverage targets. The Company considers it a high priority to utilize a portion of the excess cash flow to fund the development of new exploration successes and to selectively acquire additional assets in its core areas. The Company will also consider using a portion of the excess cash flow for share repurchases.

First quarter 2004. Based on current estimates, the Company expects that its first quarter 2004 production will average 168,000 to 183,000 BOEs per day, reflecting the incremental production from Harrier which began producing in January, the variability of oil cargo shipments in Tunisia and South Africa and the seasonal decline in gas demand during Argentina's summer season. First quarter production costs are expected to average \$5.00 to \$5.50 per BOE based on current NYMEX strip prices for oil and gas. Deprecation, depletion and amortization expense is expected to average \$7.75 to \$8.25 per BOE as a greater proportion of the Company's production is being produced from higher-cost basis deepwater Gulf of Mexico and South Africa properties. Total exploration and abandonment expense is expected to be \$25 million to \$85 million. The first quarter range includes a number of high-impact deepwater Gulf of Mexico wells that are in progress, up to five wells expected in Gabon to further refine development plans and test a new exploration target, increased exploration drilling in Argentina and the winter drilling program in Canada. General and administrative expense is expected to be \$17 million to \$20 million, \$2 million to \$3 million of which relates to estimated performance-based compensation costs. Interest expense is expected to be \$21 million to \$23 million and accretion of discount on asset retirement obligations is expected to be approximately \$2 million. The Company recognizes deferred income taxes reflecting its tax position in each of its areas of operation. However, cash income taxes are expected to be only \$3 million to \$5 million, principally related to Argentine income taxes and nominal alternative minimum tax in the United States. Other than in Argentina, the Company continues to benefit from the carryforward of net operating losses and other positive tax attributes.

Critical Accounting Estimates

The Company prepares its consolidated financial statements for inclusion in this Report in accordance with accounting principles that are generally accepted in the United States ("GAAP"). See Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a comprehensive discussion of the Company's significant accounting policies. GAAP represents a comprehensive set of accounting and disclosure rules and requirements, the application of which requires management judgments and estimates including, in certain circumstances, choices between acceptable GAAP alternatives. Following is a discussion of the Company's most critical accounting estimates, judgments and uncertainties that are inherent in the Company's application of GAAP:

Accounting for oil and gas producing activities. The accounting for and disclosure of oil and gas producing activities requires the Company's management to choose between GAAP alternatives and to make judgments about estimates of future uncertainties.

Successful efforts method of accounting. The Company utilizes the successful efforts method of accounting for oil and gas producing activities as opposed to the alternate acceptable full cost method. In general, the Company believes that, during periods of active exploration, net assets and net income are more conservatively measured under the successful efforts method of accounting for oil and gas producing activities than under the full cost method. The critical difference between the successful efforts method of accounting and the full cost method is as follows: under the successful efforts method, exploratory dry holes and geological and geophysical exploration costs are charged against earnings during the periods in which they occur; whereas, under the full cost method of accounting, such costs and expenses are capitalized as assets, pooled with the costs of successful wells and charged against the earnings of future periods as a component of depletion expense. During the years ended December 31, 2003, 2002 and 2001, the Company recognized exploration, abandonment, geological and geophysical expense of \$132.8 million, \$85.9 million and \$127.9 million, respectively, under the successful efforts method.

Proved reserve estimates. Estimates of the Company's proved reserves included in this Report are prepared in accordance with GAAP and SEC guidelines. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

The Company's proved reserve information included in this Report as of December 31, 2003 and 2002 was based on evaluations audited by independent petroleum engineers with respect to the Company's major properties and prepared by the Company's engineers with respectto all other properties. The Company's proved reserve information included in this Report as of December 31, 2001 was based on evaluations prepared by the Company's engineers. Estimates prepared by other third parties may be higher or lower than those included herein.

Because these estimates depend on many assumptions, all of which may substantially differ from future actual results, reserve estimates will be different from the quantities of oil and gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify material revisions to the estimate.

It should not be assumed that the present value of future net cash flows included in this Report as of December 31, 2003 is the current market value of the Company's estimated proved reserves. In accordance with SEC requirements, the Company based the estimated present value of future net cash flows from proved reserves on prices and costs on 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.

The Company's estimates of proved reserves materially impact depletion expense. If the estimates of proved reserves decline, the rate at which the Company records depletion expense will increase, reducing future net income. Such a decline may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields. In addition, a decline in proved reserve estimates may impact the outcome of the Company's assessment of its oil and gas producing properties for impairment.

Impairment of proved oil and gas properties. The Company reviews its long-lived proved properties to be held and used whenever management determines that events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. Management assesses whether or not an impairment provision is necessary based upon its outlook of future commodity prices and net cash flows that may be generated by the properties. Proved oil and gas properties are reviewed for impairment by depletable pool, which is the lowest levelat which depletion of proved properties is calculated.

Impairment of unproved oil and gas properties. Management periodically assesses individually significant unproved oil and gas properties for impairment, on a project-by-project basis. Management's assessment of the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects impact the amount and timing of impairment provisions.

Suspended wells. The Company suspends the costs of exploratory wells that discover hydrocarbons pending a final determination of the commercial potential of the related oil and gas fields. The ultimate disposition of these well costs is dependent on the results of future drilling activity and development decisions. If the Company decides not to pursue additional appraisal activities or development of these fields, the costs of these wells will be charged to exploration and abandonment expense. At December 31, 2003, the Company had $88.6 million of suspended exploratory well costs included in property, plant and equipment.

Assessments of functional currencies. Management determines the functional currencies of the Company's subsidiaries based on an assessment of the currency of the economic environment in which a subsidiary primarily realizes and expends its operating revenues, costs and expenses. The U.S. dollar is the functional currency of all of the Company's international operations except Canada. The assessment of functional currencies can have a significant impact on periodic results of operations and financial position.

Argentine economic and currency measures. The accounting for and remeasurement of the Company's Argentine balance sheets as of December 31, 2003 and 2002 reflect management's assumptions regarding some uncertainties unique to Argentina's current economic situation. See Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of the assumptions utilized in the preparation of these financial statements. The Argentine economic and political situation continues to evolve and the Argentine government may enact future regulations or policies that, when finalized and adopted, may materially impact, among other items, (i) the realized prices the Company receives for the commodities it produces and sells; (ii) the timing of repatriations of excess cash flow to the Company's corporate headquarters in the United States; (iii) the Company's asset valuations; and (iv) peso-denominated monetary assets and liabilities.

Deferred tax asset valuation allowances. From 1998 until 2003, the Company maintained a valuation allowance against a portion of its deferred tax asset position in the United States. Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes", requires that the Company continually assess both positive and negative evidence to determine whether it is more likely than not that the deferred tax assets can be realized prior to their expiration. In the third quarter of 2003 and as of December 31, 2003, the Company concluded that it is more likely than not that it will realize its gross deferred tax asset position in the United States after giving consideration to relevant facts and circumstances.

Accordingly, during the third quarter of 2003, the Company reversed its remaining valuation allowance in the United States, resulting in the recognition of a deferred tax benefit of $104.7 million. For 2003 in total, the Company reversed $197.7 million of United States valuation allowances resulting in a net deferred tax benefit for the year. Further, the third quarter 2003 reversal of the allowance increased stockholders' equity by $32.6 million as the Company recognized the tax effects of previous stock option exercises and deferred hedging gains and losses in other comprehensive income. See Note P of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's United States deferred tax assets and a specific discussion of the relevant facts and circumstances that were assessed.

Pioneer will continue to monitor Company-specific, oil and gas industry and worldwide economic factors and will reassess the likelihood that the Company's net operating loss carryforwards and other deferred tax attributes in each jurisdiction will be utilized prior to their expiration. There can be no assurances that facts and circumstances will not materially change and require the Company to reestablish a United States deferred tax asset valuation allowance in a future period. As of December 31, 2003, the Company does not believe there is sufficient positive evidence to reverse its valuation allowances related to foreign tax jurisdictions.

Litigation and environmental contingencies. The Company makes judgments and estimates in recording liabilities for ongoing litigation and environmental remediation. Actual costs can vary from such estimates for a variety of reasons. The costs to settle litigation can vary from estimates based on differing interpretations of laws and opinions and assessments on the amount of damages. Similarly, environmental remediation liabilities are subject to change because of changes in laws, regulations, additional information obtained relating to the extent and nature of site contamination and improvements in technology. Under GAAP, a liability is recorded for these types of contingencies if the Company determines the loss to be both probable and reasonably estimated. See Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's commitments and contingencies.

Results of Operations

Oil and gas revenues. Revenues from oil and gas operations totaled $1.3 billion during 2003, as compared to $701.8 million during 2002 and $847.0 million during 2001, representing an 85 percent increase from 2002 to 2003. The revenue increase from 2002 to 2003 was due to a 36 percent increase in BOE production, a 12 percent increase in oil prices, a 40 percent increase in NGL prices and a 53 percent increase in gas prices, including the effects of commodity price hedges. The increased production is principally attributable to incremental gas production from the deepwater Gulf of Mexico Canyon Express and Falcon field projects, initial oil production in South Africa and Tunisia and increased oil and gas production in Argentina, offset by normal production declines. The revenue decrease from 2001 to 2002 was principally due to year-on-year worldwide average oil, NGL and gas price declines of five percent, 19 percent and 23 percent, respectively, including the effects of commodity price hedges, and an eight percent decline in worldwide oil production, partially offset by worldwide NGL and gas production increases of four percent and two percent, respectively.

The following table provides production volumes and average reported prices, including the results of hedging activities, by geographic area and in total, for the years ended December 31, 2003, 2002 and 2001:

	Year ended December 31,		
	2003	2002	2001
Average daily production:			
Oil (Bbls)			
United States	24,525	23,437	23,641
Argentina	8,687	7,984	9,769
Canada	111	124	831
Africa	1,981	-	-
Worldwide	35,304	31,545	34,241
NGLs (Bbls)			
United States	20,338	20,512	19,815
Argentina	1,318	696	547
Canada	906	946	1,008
Worldwide	22,562	22,154	21,370
Gas (Mcf)			
United States	445,609	232,360	212,629
Argentina	94,128	78,220	87,204
Canada	41,669	48,365	50,481
Worldwide	581,406	358,945	350,314
Total (BOE)			
United States	119,129	82,677	78,893
Argentina	25,694	21,716	24,851
Canada	7,962	9,131	10,253
Africa	1,981	-	-
Worldwide	154,766	113,524	113,997
Average reported prices:			
Oil (per Bbl)			
United States	$ 25.25	$ 23.66	$ 24.34
Argentina	$ 25.62	$ 20.63	$ 23.79
Canada	$ 29.10	$ 22.26	$ 21.87
Africa	$ 29.52	$ -	$ -
Worldwide	$ 25.59	$ 22.89	$ 24.12
NGL (per Bbl)			
United States	$ 19.04	$ 13.77	$ 16.88
Argentina	$ 22.85	$ 14.56	$ 19.29
Canada	$ 24.80	$ 16.77	$ 21.11
Worldwide	$ 19.50	$ 13.92	$ 17.14
Gas (per Mcf)			
United States	$ 4.49	$ 3.16	$ 4.10
Argentina	$ .56	$ .48	$ 1.31
Canada	$ 3.90	$ 2.50	$ 2.86
Worldwide	$ 3.81	$ 2.49	$ 3.23
Annual percentage increase (decrease) in average worldwide reported prices:			
Oil	12	(5)	-
NGL	40	(19)	(15)
Gas	53	(23)	15

Hedging activities. The oil and gas prices that the Company reports are based on the market price received for the commodities adjusted by the results of the Company's cash flow hedging activities. The Company utilizes commodity swap and collar contracts in order to (i) reduce the effect of price volatility on the commodities the Company produces and sells, (ii) support the Company's annual capital budgeting and expenditure plans and (iii) reduce commodity price risk associated with certain capital projects. The effective portions of changes in the fair values of the Company's commodity price hedges are deferred as increases or decreases to stockholders' equity until the underlying hedged transaction occurs. Consequently, changes in the effective portions of commodity price hedges add volatility to the

Company's reported stockholders' equity until the hedge derivative matures or is terminated. See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information concerning the impact to oil and gas revenues during the years ended December 31, 2003, 2002 and 2001 from the Company's hedging activities, the Company's open hedge positions at December 31, 2003 and descriptions of the Company's hedge and non-hedge commodity derivatives. Also see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional disclosure about the Company's commodity related derivative financial instruments.

Interest and other income. The Company recorded interest and other income totaling $12.3 million, $11.2 million and $21.8 during the years ended December 31, 2003, 2002 and 2001, respectively. The Company's interest and other income was comprised of revenue that was not directly attributable to oil and gas producing activities or oil and gas property divestitures. See Note M of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding interest and other income.

Gain on disposition of assets. During the years ended December 31, 2003, 2002 and 2001, the Company completed asset divestitures for net proceeds of $35.7 million, $118.9 million and $113.5 million, respectively. Associated therewith, the Company recorded gains on disposition of assets of $1.3 million, $4.4 million and $7.7 million during the years ended December 31, 2003, 2002 and 2001, respectively.

The net cash proceeds from asset divestitures during the years ended December 31, 2003, 2002 and 2001 were used, together with net cash flows provided by operating activities, to fund additions to oil and gas properties and to reduce outstanding indebtedness. See Note N of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding asset divestitures.

Oil and gas production costs. The Company recorded production costs of $279.5 million, $199.6 million and $209.7 million during the years ended December 31, 2003, 2002 and 2001, respectively. The increase in total production costs during 2003 as compared to 2002 is primarily attributable to the increase in production volumes, while the decrease in total production costs during 2002 as compared to 2001 is principally attributable to lower production tax and field fuel expenses due to lower commodity prices.

Total production costs per BOE increased during the year ended December 31, 2003 by three percent and decreased during the year ended December 31, 2002 by four percent. In general, lease operating expenses and workover expenses represent the components of oil and gas production costs over which the Company has management control, while production taxes, ad valorem taxes and field fuel expenses are directly related to commodity price changes. The increase in production costs per BOE during 2003 was primarily due to increases in per BOE lease operating expenses, field fuel expenses and production taxes, partially offset by decreases in per BOE ad valorem taxes and workover expenses. The increase in per BOE lease operating expenses was due to the strengthening of both the Argentine peso and the Canadian dollar, Argentine inflation and higher average lifting costs incurred on South African Sable oil field production, while the increases in per BOE field fuel expenses and production taxes primarily resulted from increases in North American gas prices and world oil prices. The decrease in per BOE ad valorem taxes is primarily due to the incremental production from the deepwater Gulf of Mexico, Argentina, South Africa and Tunisia fields which are not subject to ad valorem taxes.

The decrease in production costs during 2002 was primarily due to decreases in field fuel expense and production taxes as a result of lower North American average gas prices and lower Argentine lease operating expenses resulting from lower Argentine expenses on a U.S. dollar equivalent basis due to the devaluation of the Argentine peso versus the U.S. dollar, partially offset by moderately higher workover expenses, ad valorem taxes (which are computed using prior year average annual commodity prices) and declines in the third party gas processing and treating margin component of lease operating expense.

The following tables provide the components of the Company's total production costs per BOE and total production costs per BOE by geographic area for the years ended December 31, 2003, 2002 and 2001:

	Year Ended December 31,		
	2003	2002	2001
Lease operating expenses	$ 3.07	$ 2.87	$ 2.76
Taxes:			
Production	.62	.54	.74
Ad valorem	.40	.54	.49
Field fuel expenses	.72	.62	.88
Workover expenses	.14	.25	.17
Total production costs	$ 4.95	$ 4.82	$ 5.04

	Year Ended December 31,		
	2003	2002	2001
Total production costs:			
United States	$ 5.46	$ 5.80	$ 5.92
Argentina	$ 2.78	$ 1.75	$ 2.93
Canada	$ 4.49	$ 3.23	$ 3.33
Africa	$ 3.99	$ -	$ -
Worldwide	$ 4.95	$ 4.82	$ 5.04

Depletion, depreciation and amortization expense. The Company's total depletion, depreciation and amortization expense per BOE was $6.92, $5.22 and $5.35 for the years ended December 31, 2003, 2002 and 2001, respectively. Depletion expense, the largest component of depletion, depreciation and amortization, was $6.75, $5.01 and $5.02 per BOE during the years ended December 31, 2003, 2002 and 2001, respectively, and depreciation and amortization of other property and equipment was $.17, $.21 and $.33 per BOE during each of the respective years. During 2003, the increase in per BOE depletion expense was due to increases in higher cost-basis deepwater Gulf of Mexico and South African production volumes and downward revisions to proved reserves in Canada.

The following table provides depletion expense per BOE by geographic area for the years ended December 31, 2003, 2002 and 2001:

	Year Ended December 31,		
	2003	2002	2001
Depletion expense:			
United States	$ 6.85	$ 4.64	$ 4.46
Argentina	$ 4.96	$ 5.00	$ 5.67
Canada	$ 9.98	$ 8.36	$ 7.71
Africa	$ 10.69	$ -	$ -
Worldwide	$ 6.75	$ 5.01	$ 5.02

Exploration, abandonments, geological and geophysical costs. Exploration, abandonments, geological and geophysical costs totaled $132.8 million, $85.9 million and $127.9 million during the years ended December 31, 2003, 2002 and 2001, respectively. The following table sets forth the components of the Company's exploration, abandonments, geological and geophysical costs by geographic region for the years ended December 31, 2003, 2002 and 2001:

	United States	Argentina	Canada	Africa and Other	Total
			(in thousands)		
Year Ended December 31, 2003:					
Geological and geophysical costs	$ 40,783	$ 7,689	$ 4,426	$ 3,903	$ 56,801
Exploratory dry holes	27,015	2,672	10,963	20,250	60,900
Leasehold abandonments and other	4,934	7,715	2,302	108	15,059
	$ 72,732	$ 18,076	$ 17,691	$ 24,261	$ 132,760
Year Ended December 31, 2002:					
Geological and geophysical costs	$ 22,761	$ 4,138	$ 3,544	$ 7,223	$ 37,666
Exploratory dry holes	32,557	3,294	1,220	(539)	36,532
Leasehold abandonments and other	7,637	2,874	1,077	108	11,696
	$ 62,955	$ 10,306	$ 5,841	$ 6,792	$ 85,894
Year Ended December 31, 2001:					
Geological and geophysical costs	$ 29,620	$ 6,541	$ 2,373	$ 13,678	$ 52,212
Exploratory dry holes	34,883	6,040	5,473	10,432	56,828
Leasehold abandonments and other	5,546	11,276	2,036	8	18,866
	$ 70,049	$ 23,857	$ 9,882	$ 24,118	$ 127,906

The increase in 2003 exploration, abandonments, geological and geophysical expense, as compared to 2002, was primarily due to increased geological and geophysical expenditures supportive of exploration activities in the Gulf of Mexico and Alaska and a $24.4 million increase in exploratory dry hole expense. The increase in exploratory dry hole expense during 2003 was primarily due to an increase in Canadian exploratory drilling activities and three unsuccessful wells drilled in South Africa and one unsuccessful well drilled in Tunisia.

The decrease in 2002 exploration, abandonments, geological and geophysical expense reflected a decline in Argentine exploration activities as the Company monitored and assessed the economic environment and risks associated with Argentina; a decline in exploratory dry holes and geological and geophysical expense in Africa, as the Company assessed its exploratory successes in Gabon and Tunisia; and the allocation of a larger percentage of the Company's 2002 capital budget to the development of its significant discoveries in the Gulf of Mexico and offshore South Africa.

Approximately 38 percent of the Company's 2003 costs incurred for oil and gas producing activities were exploration costs as compared to 20 percent in 2002 and 34 percent in 2001.

General and administrative expenses. The Company's general and administrative expenses totaled $60.5 million ($1.07 per BOE), $48.4 million ($1.17 per BOE) and $37.0 million ($.89 per BOE) during the years ended December 31, 2003, 2002 and 2001, respectively. The increase in general and administrative expense during 2003, as compared to 2002, was primarily due to increases in administrative staff and performance-related compensation costs, including the amortization of restricted stock awarded to officers, directors and key employees during 2003 and 2002.

The increase in administrative expense during the year ended December 31, 2002 as compared to 2001 was primarily due to the elimination of operating overhead being charged by the Company to the 42 affiliated partnerships that were merged into a wholly-owned subsidiary of the Company during December 2001 and amortization of restricted stock awarded in 2002.

See Notes D and G of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the affiliated partnership mergers and the restricted stock awards in 2003 and 2002 and their vesting periods, respectively.

Accretion of discount on asset retirement obligations. During the year ended December 31, 2003 the Company recorded accretion of discount on asset retirement obligations of $5.0 million. The provisions of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143") require that the accretion of discount on asset retirement obligations be classified in the consolidated statement of operations separate from interest expense. Prior to 2003 and the adoption of SFAS 143, the Company classified accretion of discount on asset retirement obligations as a component of interest expense. The Company's interest expense during each of the years ended December 31, 2002 and 2001 included $2.6 million of accretion of discount on asset retirement obligations that was calculated prior to the adoption of SFAS 143 based on asset retirement obligations recorded in purchased business combinations. See "Cumulative effect of change in accounting principle" below and Notes B and L of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's adoption of SFAS 143.

Interest expense. Interest expense was $91.4 million, $95.8 million and $132.0 million during the years ended December 31, 2003, 2002 and 2001, respectively, while the weighted average interest rate on the Company's indebtedness for the year ended December 31, 2003 was 5.3 percent as compared to 5.7 percent and 7.5 percent for the years ended December 31, 2002 and 2001, respectively, taking into account the effect of interest rate swaps. The decrease in interest expense for 2003 as compared to 2002 was primarily due to $4.8 million of interest savings associated with the July 2002 repayment of a $45.2 million West Panhandle gas field capital obligation (the "West Panhandle Capital Obligation") which bore interest at an annual rate of 20 percent; $4.1 million of incremental savings from the Company's interest rate hedging program; a $2.6 million decrease in accretion expense (see "Accretion of discount on asset retirement obligations", above); and lower underlying market interest rates and outstanding debt. Partially offsetting the decreases in interest expense was a $6.8 million decrease in interest capitalized during 2003 as compared to 2002 due to the completion of the Canyon Express and Falcon field development projects.

The decline in 2002 interest expense as compared to 2001, was primarily due to incremental interest savings of $18.0 million from the Company's interest rate hedging program; a $6.3 million increase in interest capitalized; interest savings from the retirement of the Company's outstanding 11-5/8 percent and 10-5/8 percent senior subordinated notes during the third quarter of 2001and $38.7 million of the Company's 9-5/8 percent senior notes during the fourth quarter of 2001; interest savings from the repurchase of $47.1 million of 9-5/8 percent senior notes and $13.9 million of 8-7/8 percent senior notes during 2002; interest savings from the repayment of West Panhandle Capital Obligation; and interest savings from reductions in underlying market interest rates.

See Note E of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information about the Company's long-term debt and interest expense.

Other expenses. Other expenses were $21.3 million during the year ended December 31, 2003, as compared to $39.6 million during 2002 and $43.3 million during 2001. See Note O of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a detail of the components included in other expenses.

Income tax provisions (benefits). The Company recognized a consolidated income tax benefit of $64.4 million during the year ended December 31, 2003 and consolidated income tax provisions of $5.1 million and $4.0 million during the years ended December 31, 2002 and 2001, respectively. The Company's consolidated tax benefit in 2003 was comprised of a $.1 million current United States federal tax provision, an $11.1 million current foreign income tax provision, $76.3 million of deferred United States federal and state tax benefits and $.7 million of deferred foreign tax provisions. The 2003 deferred United States federal and state tax benefits include a $197.7 million benefit from the reversal of the Company's valuation allowances against United States deferred tax assets, of which $104.7 million was reversed in the third quarter of 2003. As a result of the reversal of the valuation allowances against the Company's United States deferred tax assets, the effective tax rate on the Company's future earnings in the United States will approximate statutory rates.

The Company's consolidated tax provision for 2002 was comprised of current United States state and local taxes of $.2 million, current foreign taxes of $2.1 million and deferred foreign tax provisions of $2.8 million. The Company's consolidated tax provision for 2001 was comprised of current U.S. state and local taxes of $1.1 million, current foreign taxes of $10.5 million and deferred foreign tax benefits of $7.6 million.

See "Critical Accounting Estimates" above and Note P of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's tax position.

Cumulative effect of change in accounting principle. As previously discussed, the Company adopted the provisions of SFAS 143 on January 1, 2003 and recognized a $15.4 million benefit from the cumulative effect of change in accounting principle, net of $1.3 million of associated Argentine deferred income taxes during the year ended December 31, 2003.

On January 1, 2003, the Company also adopted the provisions of Statement of Financial Accounting Standards No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections" ("SFAS 145"), the provisions of which did not result in a cumulative effect adjustment. In accordance with the provisions of SFAS 145, the Company reclassified to other expense extraordinary losses from the early extinguishment of debt of $22.3 million and $3.8 million realized during the years ended December 31, 2002 and 2001, respectively.

See Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's adoption of SFAS 143 and SFAS 145.

Capital Commitments, Capital Resources and Liquidity

Capital commitments. The Company's primary needs for cash are for exploration, development and acquisitions of oil and gas properties, repayment of contractual obligations and working capital funding. Funding for exploration, development and acquisitions of oil and gas properties and repayment of contractual obligations may be provided by any combination of internally-generated cash flow, proceeds from the disposition of non-strategic assets or alternative financing sources as discussed in "Capital resources" below. Funding for the Company's working capital obligations is provided by internally-generated cash flows.

Oil and gas properties. The Company's cash expenditures for additions to oil and gas properties during the years ended December 31, 2003, 2002 and 2001 totaled $688.1 million, $614.7 million and $529.7 million, respectively. The Company's 2003 expenditures for additions to oil and gas properties were internally funded by $763.7 million of net cash provided by operating activities. The Company's 2002 expenditures for additions to oil and gas properties were funded by $332.2 million of net cash provided by operating activities, $118.9 million of proceeds from the disposition of assets and a portion of the proceeds from the issuance of 11.5 million shares of the Company's common stock during April 2002. The Company's 2001 expenditures were internally funded by $475.6 million of net cash provided by operating activities and a portion of the Company's $113.5 million of proceeds from disposition of assets.

The Company strives to maintain its indebtedness at reasonable levels in order to provide sufficient financial flexibility to take advantage of future opportunities. The Company's capital budget for 2004 is expected to range from $550 million to $600 million. The Company believes that net cash provided by operating activities during 2004 will be sufficient to fund the 2004 capital expenditures budget as well as reduce long-term debt by a minimum of $100 million and fund the recently approved plan to begin an annual dividend program of $.20 per common share beginning in 2004. For additional information regarding the Company's plans for 2004, see "2004 Outlook" above.

Contractual obligations, including off-balance sheet obligations. The Company's contractual obligations include long-term debt, operating leases, drilling commitments, derivative obligations and other liabilities. From time to time, the Company enters into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations of the Company. As of December 31, 2003, the material off-balance sheet arrangements and transactions that the Company has entered into include (i) $47.6 million of undrawn letters of credit, (ii) operating lease agreements, (iii) drilling commitments and (iv) contractual obligations for which the ultimate settlement amounts are not fixed and determinable such as derivative contracts that are sensitive to future changes in commodity prices and gas transportation commitments. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for a table of changes in the fair value of the Company's derivative contract assets and liabilities during the year ended December 31, 2003 and Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding future minimum lease payments and gas transportation commitments.

The following table summarizes by period the Company's payments due for contractual obligations estimated as of December 31, 2003:

	Payments Due by Year			
	2004	2005 and 2006	2007 and 2008	Thereafter
		(in thousands)		
Long-term debt (a)	$ -	$ 135,239	$ 669,750	$ 750,472
Operating leases (b)	35,515	81,669	44,950	24,174
Drilling commitments (c)	13,601	6,902	602	-
Derivative obligations (d)	161,574	41,640	7,185	-
Other liabilities (e)	38,798	36,201	32,790	76,650
	$ 249,488	$ 301,651	$ 755,277	$ 851,296

(a) See Note E of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".
(b) See Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".
(c) Drilling commitments represent future minimum expenditure commitments under contracts that the Company was a party to on December 31, 2003 for drilling rig services and well commitments.
(d) Derivative obligations represent net liabilities for oil and gas commodity derivatives that were valued as of December 31, 2003. These liabilities include $8.8 million of current liabilities that are fixed in amount and are not subject to continuing market risk. The ultimate settlement amounts of the remaining portions of the Company's derivative obligations are unknown because they are subject to continuing market risk. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's derivative obligations.
(e) The Company's other liabilities represent current and noncurrent other liabilities that are comprised of benefit obligations, litigation contingencies, asset retirement obligations and other obligations for which neither the ultimate settlement amounts nor their timings can be precisely determined in advance. See Notes G, I and L of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's benefit obligations, litigation contingencies and asset retirement obligations, respectively.

Capital resources. The Company's primary capital resources are net cash provided by operating activities, proceeds from financing activities and proceeds from sales of non-strategic assets. The Company expects that these resources will be sufficient to fund its capital commitments in 2004.

Operating activities. Net cash provided by operating activities during the years endedDecember 31, 2003, 2002 and 2001 were $763.7 million, $332.2 million and $475.6 million, respectively. Net cash provided by operating activities in 2003 increased by $431.5 million, or 130 percent, as compared to that of 2002. The increase in 2003 was primarily due to increased production volumes and higher commodity prices as compared to 2002. Net cash provided by operating activities in 2002 decreased by $143.4 million, or 30 percent, as compared to that of 2001. The decrease in 2002 net cash provided by operating activities was principally due to declines in commodityprices, offset partially by declines in interest expense.

Investing activities. Net cash used in investing activities during the years ended December 31, 2003, 2002 and 2001were $662.3 million, $508.1 million and $422.7 million. The $154.2 million increase in cash used in investing activities during 2003 as compared to 2002 was primarily due to a $73.4 million increase in additions to oil and gas properties and an $83.2 million decrease in proceeds from disposition of assets. The cash proceeds from asset divestitures during 2003 were used to reduce outstanding indebtedness. The cash proceeds from asset divestitures during 2002 and 2001 were used to fund a portion of the Company's 2002 and 2001 capital expenditures and for general corporate obligations. See "Results of Operations", above, and Note N of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding asset divestitures.

Financing activities. Net cash used in financing activities totaled $91.7 million and $64.0 million during the years ended December 31, 2003 and 2001. During the year ended December 31, 2002, financing activities provided $170.9 million of net cash. During 2003, financing activities were comprised of $105.5 million of net principle payments on long-term debt, $14.1 million of payments of other noncurrent liabilities, $2.8 million of loan fees and $2.3 million of treasury stock purchases, partially offset by $33.0 million of proceeds from the exercise of long-term incentive plan stock options and employee stock purchases. During 2002, the Company's financing activities were comprised of $236.0 million of proceeds, net of issuance costs, from the sale of 11.5 million shares of the Company's common stock; $48.0 million of net borrowings of long-term debt; and $14.4 million of proceeds from the exercise of long-term incentive plan stock options and employee stock purchases, partially offset by $124.2 million of payments of other noncurrent liabilities and $3.3 million of debt issuance costs. During 2001, the Company's financing activities were comprised of $5.1 million to repay long-term debt, $53.4 million to repay other noncurrent liabilities and $13.0 million to purchase treasury stock, partially offset by $7.5 million of net cash provided from the exercise of long-term incentive plan stock options and employee stock purchases.

Over the three-year period ended December 31, 2003, the Company has entered into financing transactions with the intent of reducing its cost of capital and increasing liquidity through the extension of debt maturities. See Notes E and J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplemental Data" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for more information about the Company's debt instruments and interest rate hedging activities.

The Company's future debt level is dependent primarily on net cash provided by operating activities, proceeds from financing activities and proceeds generated from asset dispositions. The Company believes it has substantial borrowing capacity to meet any unanticipated cash requirements, and during low commodity price periods, the Company has the flexibility to increase borrowings and/or modify its capital spending to meet its contractual obligations and maintain its debt ratings.

As the Company pursues its strategy, it may utilize various financing sources, including fixed and floating rate debt, convertible securities, preferred stock or common stock. The Company may also issue securities in exchange for oil and gas properties, stock or other interests in other oil and gas companies or related assets. Additional securities may be of a class preferred to common stock with respect to such matters as dividends and liquidation rights and may also have other rights and preferences as determined by the Company's Board of Directors.

Liquidity. The Company's principal source of short-term liquidity is its revolving credit facility. During December 2003, the Company entered into a new five-year revolving credit agreement (the "New Credit Facility") that matures in December 2008. The New Credit Facility replaced the Company's $575 million revolving credit facility (the "Prior Credit Facility") that had a scheduled maturity in March 2005. The terms of the New Credit Facility provide for initial aggregate loan commitments of $700 million from a syndication of participating banks (the "Lenders"). Aggregate loan commitments under the New Credit Facility may be increased to a maximum aggregate amount of $1 billion if the Lenders increase their loan commitments or loan commitments of new financial institutions are added to the New Credit Facility. Outstanding borrowings under the New Credit Facility totaled $160 million as of December 31, 2003. Including $28.8 million of undrawn and outstanding letters of credit under the New Credit Facility, the Company has $511.2 million of unused borrowing capacity as of December 31, 2003.

Book capitalization and current ratio. The Company's book capitalization at December 31, 2003 was $3.3 billion, consisting of debt of $1.6 billion and stockholders' equity of $1.7 billion. The Company's debt to book capitalization was 46.9 percent at December 31, 2003 as compared to 54.8 percent at December 31, 2002. The Company's ratio of current assets to current liabilities was .48 at December 31, 2003 and .54 at December 31, 2002. The decline in the Company's ratio of current assets to current liabilities was primarily due to increases in current hedge derivative obligations and trade payables. As more fully discussed in "2004 Outlook" above, the Company has targeted a range for debt to book capitalization of between 37 percent and 43 percent.

New Accounting Development

In its recent review of registrants' filings, the staff of the SEC has taken the position that Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" ("SFAS 142"), requires oil and gas entities to separately report on their balance sheets the costs of leasehold mineral interests, including related accumulated depletion, as intangible assets and provide related disclosures. The Company has historically included producing leasehold costs in the proved properties caption on its balance sheet since the value of the leases is inseparable from the value of the related oil and gas reserves. This classification is consistent with the provisions of Statement of Financial Accounting Standards No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies", and standard industry practice. Almost all costs included in the unproved properties caption on the balance sheet are leasehold mineral interests that are regularly evaluated for impairment based on lease term and drilling activity. The SEC staff has referred the question of SFAS 142 applicability for consideration by the Emerging Issues Task Force. If the provisions of SFAS 142 are determined to be applicable to oil and gas leasehold mineral interests, reclassifications within property, plant and equipment on the Consolidated Balance Sheets and additional disclosures may be required. As of December 31, 2003, the Company has not determined the amount of such reclassifications, if applicable. The Company does not believe that the provisions of SFAS 142, if determined to be applicable, will have a material impact on its financial position, results of operations or liquidity.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The following quantitative and qualitative information is provided about financial instruments to which the Company was a party as of December 31, 2003 and 2002, and from which the Company may incur future gains or losses from changes in market interest rates, foreign exchange rates or commodity prices. Although certain derivative contracts that the Company is a party to do not qualify as hedges, the Company does not enter into derivative or other financial instruments for trading purposes.

The fair value of the Company's derivative contracts are determined based on counterparties' estimates and valuation models. The Company did not change its valuation method during the year ended December 31, 2003. During 2003, the Company was a party to forward foreign exchange contracts, commodity and interest rate swap contracts and commodity collar contracts. See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's derivative contracts, including deferred gains and losses on terminated derivative contracts. The following table reconciles the changes that occurred in the fair values of the Company's open derivative contracts during 2003:

	Derivative Contract Assets (Liabilities)			
	Commodity	Interest Rate	Foreign Exchange Rate	Total
	(in thousands)			
Fair value of contracts outstanding as of December 31, 2002	$ (108,804)	$ -	$ 15	$(108,789)
Changes in contract fair values (a)	(282,530)	21,497	3	(261,030)
Contract realizations:				
Maturities	136,425	(3,230)	(18)	133,177
Termination - cash settlements	125	(18,267)	-	(18,142)
Termination - future net obligations	53,362	-	-	53,362
Fair value of contracts outstanding as of December 31, 2003	$ (201,422)	$ -	$ -	$(201,422)

(a) At inception, new derivative contracts entered into by the Company have no intrinsic value.

Quantitative Disclosures

Interest rate sensitivity. The following tables provide information about other financial instruments that the Company was a party to as of December 31,2003 and 2002 and that are or were sensitive to changes in interest rates. For debt obligations, the tables present maturities by expected maturity dates, the weighted average interest rates expected to be paid on the debt given current contractual terms and market conditions and the debt's estimated fair value. For fixed rate debt, the weighted average interest rate represents the contractual fixed rates that the Company was obligated to periodically pay on the debt as of December 31, 2003 and 2002. For variable rate debt, the average interest rate represents the average rates being paid on the debt projected forward proportionate to the forward yield curve for the six-month LIBOR.

Interest Rate Sensitivity
Debt Obligations as of December 31, 2003

	Year Ended December 31,							Liability Fair Value at December 31,
	2004	2005	2006	2007	2008	Thereafter	Total	2003
	(in thousands, except interest rates)							
Total Debt:								
Fixed rate maturities	$ -	$135,239	$ -	$155,253	$354,497	$ 750,472	$1,395,461	$(1,549,026)
Weighted average interest rate (%)	7.93	7.86	7.83	7.81	8.34	8.37		
Variable rate maturities	$ -	$ -	$ -	$ -	$160,000	$ -	$ 160,000	$ (160,000)
Average interest rate (%) ...	2.87	4.28	5.27	5.91	6.28	-		

Interest Rate Sensitivity
Debt Obligations as of December 31, 2002

	Year Ended December 31,							Liability Fair Value at December 31,
	2003	2004	2005	2006	2007	Thereafter	Total	2002
	(in thousands, except interest rates)							
Total Debt:								
Fixed rate maturities	$ -	$ -	$146,704	$ -	$161,130	$1,100,702	$1,408,536	$ (1,484,009)
Weighted average interest rate (%)	7.94	7.94	7.87	7.83	7.81	7.77		
Variable rate maturities	$ -	$ -	$260,000	$ -	$ -	$ -	$ 260,000	$ (260,000)
Average interest rate (%) ...	2.89	4.08	5.27	-	-	-		

Foreign exchange rate sensitivity. There were no outstanding foreign exchange rate hedge derivatives at December 31, 2003. As of December 31, 2002, the Company was a party to a foreign exchange rate derivative that matured during January 2003 as an $18 thousand asset of the Company.

Commodity price sensitivity. The following tables provide information about the Company's oil and gas derivative financial instruments that were sensitive to changes in oil and gas prices as of December 31, 2003 and 2002. As of December 31, 2003 and 2002, all of the Company's oil and gas derivative financial instruments qualified as hedges.

Commodity hedge instruments. The Company hedges commodity price risk with swap and collar contracts. Swap contracts provide a fixed price for a notional amount of sales volumes. Collar contracts provide minimum ("floor") and maximum ("ceiling") prices for the Company on a notional amount of sales volumes, thereby allowing some price participation if the relevant index price closes above the floor price.

See Notes B, C and J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of the accounting procedures followed by the Company relative to hedge derivative financial instruments and for specific information regarding the terms of the Company's derivative financial instruments that are sensitive to changes in oil and gas prices.

Oil Price Sensitivity
Derivative Financial Instruments as of December 31, 2003

	Year Ended December 31, 2004	2005	2006	2007	2008	Liability Fair Value at December 31, 2003 (in thousands)
Oil Hedge Derivatives (a):						
Average daily notional Bbl volumes:						
Swap contracts	18,973	17,000	5,000	1,000	5,000	$ (50,240)
Weighted average fixed price per Bbl	$ 25.84	$ 24.93	$ 26.19	$ 26.00	$ 26.09	
Average forward NYMEX oil prices (b)	$ 30.12	$ 28.03	$ 27.09	$ 26.55	$ 26.60	

(a) See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for hedge volumes and weighted average prices per Bbl by calendar quarter.

(b) The average forward NYMEX oil prices per Bbl are based on January 30, 2004 market quotes.

Oil Price Sensitivity
Derivative Financial Instruments as of December 31, 2002

	Year Ended December 31, 2003	2004	Liability Fair Value at December 31, 2002 (in thousands)
Oil Hedge Derivatives:			
Average daily notional Bbl volumes:			
Swap contracts	22,236	14,000	$ (19,912)
Weighted average fixed price per Bbl	$ 24.45	$ 23.11	
Average forward NYMEX oil prices (a)	$ 31.55	$ 25.75	

(a) The average forward NYMEX oil prices are based on February 18, 2003 market quotes.

Gas Price Sensitivity
Derivative Financial Instruments as of December 31, 2003

	Year Ended December 31, 2004	2005	2006	2007	Liability Fair Value at December 31, 2003 (in thousands)
Gas Hedge Derivatives (a):					
Average daily notional Mcf volumes (b):					
Swap contracts (c)	283,962	60,000	70,000	20,000	$ (151,182)
Weighted average fixed price per MMBtu	$ 4.16	$ 4.24	$ 4.16	$ 3.51	
Average forward NYMEX gas prices (d)	$ 4.66	$ 5.04	$ 4.74	$ 4.60	

(a) To minimize basis risk, the Company enters into basis swaps for a portion of its gas hedges to convert the index price of the hedging instrument from a NYMEX index to an index which reflects the geographic area of production. The Company considers these basis swaps as part of the associated swap and collar contracts and, accordingly, the effects of the basis swaps have been presented together with the associated contracts.

(b) See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for hedge volumes and weighted average prices per MMBtu by calendar quarter.

(c) During January 2004, the Company increased its 2004 gas hedge positions by entering into 32,967 Mcf per day of first quarter 2004 gas swap contracts with weighted average per MMBtu fixed prices of $7.11.

(d) The average forward NYMEX gas prices per MMBtu are based on January 30, 2004 market quotes.

Gas Price Sensitivity
Derivative Financial Instruments as of December 31, 2002

	Year Ended December 31,				Liability Fair Value at December 31, 2002
	2003	2004	2005	2006 & 2007	(in thousands)
Gas Hedge Derivatives (a):					
Average daily notional Mcf volumes:					
Swap contracts	230,000	180,000	10,000	20,000	$ (88,892)
Weighted average fixed price per MMBtu	$ 3.76	$ 3.81	$ 3.70	$ 3.75	
Average forward NYMEX gas prices (b)	$ 5.53	$ 4.80	$ 4.31	$ 4.12	

(a) To minimize basis risk, the Company enters into basis swaps for a portion of its gas hedges to convert the index price of the hedging instrument from a NYMEX index to an index which reflects the geographic area of production. The Company considers these basis swaps as part of the associated swap and collar contracts and, accordingly, the effects of the basis swaps have been presented together with the associated contracts.
(b) The average forward NYMEX gas prices per MMBtu are based on February 18, 2003 market quotes.

Qualitative Disclosures

Non-derivative financial instruments. The Company is a borrower under fixed rate and variable rate debt instruments that give rise to interest rate risk. The Company's objective in borrowing under fixed or variable rate debt is to satisfy capital requirements while minimizing the Company's costs of capital. See Note E of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a discussion of the Company's debt instruments.

Derivative financial instruments. The Company utilizes interest rate, foreign exchange rate and commodity price derivative contracts to hedge interest rate, foreign exchange rate and commodity price risks in accordance with policies and guidelines approved by the Company's board of directors. In accordance with those policies and guidelines, the Company's executive management determines the appropriate timing and extent of hedge transactions.

As of December 31, 2003, the Company's primary risk exposures associated with financial instruments to which it is a party include oil and gas price volatility, volatility in the exchange rates of the Canadian dollar and Argentine peso vis á vis the U.S. dollar and interest rate volatility. The Company's primary risk exposures associated with financial instruments have not changed significantly since December 31, 2003.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Consolidated Financial Statements

INDEPENDENT AUDITORS' REPORT

The Board of Directors and Shareholders
Pioneer Natural Resources Company:

We have audited the accompanying consolidated balance sheets of Pioneer Natural Resources Company (the "Company") as of December 31, 2003 and 2002, and the related consolidated statements of operations, stockholders' equity, cash flows and comprehensive income (loss) 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 consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company at 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 B to the consolidated financial statements, in 2003 the Company adopted Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations". Also, as discussed in Note B to the consolidated financial statements, in 2001 the Company adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities".

Ernst & Young LLP

Dallas, Texas
January 26, 2004

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

ASSETS

	December 31, 2003	December 31, 2002
Current assets:		
Cash and cash equivalents	$ 19,299	$ 8,490
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $4,727 and $4,744 as of December 31, 2003 and 2002, respectively	111,033	97,774
Due from affiliates	447	448
Inventories	17,509	10,648
Prepaid expenses	11,083	5,485
Deferred income taxes	40,514	13,900
Other current assets:		
Derivatives	423	2,508
Other, net of allowance for doubtful accounts of $4,486 and $3,351 as of December 31, 2003 and 2002, respectively	4,807	7,840
Total current assets	205,115	147,093
Property, plant and equipment, at cost:		
Oil and gas properties, using the successful efforts method of accounting:		
Proved properties	4,983,558	4,252,897
Unproved properties	179,825	219,073
Accumulated depletion, depreciation and amortization	(1,676,136)	(1,303,541)
Total property, plant and equipment	3,487,247	3,168,429
Deferred income taxes	192,344	76,840
Other property and equipment, net	28,080	22,784
Other assets:		
Derivatives	209	643
Other, net of allowance for doubtful accounts of $92 and $1,227 as of December 31, 2003 and 2002, respectively	38,577	39,327
	$ 3,951,572	$ 3,455,116

LIABILITIES AND STOCKHOLDERS' EQUITY

	2003	2002
Current liabilities:		
Accounts payable:		
Trade	$ 177,614	$ 117,582
Due to affiliates	8,804	7,192
Interest payable	37,034	37,458
Income taxes payable	5,928	-
Other current liabilities:		
Derivatives	161,574	83,638
Other	38,798	28,722
Total current liabilities	429,752	274,592
Long-term debt	1,555,461	1,668,536
Derivatives	48,825	42,490
Deferred income taxes	12,121	8,760
Other liabilities	145,641	85,841
Stockholders' equity:		
Common stock, $.01 par value; 500,000,000 shares authorized; 119,665,784 and 119,592,344 shares issued at December 31, 2003 and 2002, respectively	1,197	1,196
Additional paid-in capital	2,734,403	2,714,567
Treasury stock, at cost; 378,012 and 2,339,806 shares at December 31, 2003 and 2002, respectively	(5,385)	(32,219)
Deferred compensation	(9,933)	(14,292)
Accumulated deficit	(887,848)	(1,298,440)
Accumulated other comprehensive income (loss):		
Net deferred hedge gains (losses), net of tax	(104,130)	9,555
Cumulative translation adjustment	31,468	(5,470)
Total stockholders' equity	1,759,772	1,374,897
Commitments and contingencies		
	$ 3,951,572	$ 3,455,116

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

PIONEER NATURAL RESOURCES COMPANY

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

	Year Ended December 31,		
	2003	2002	2001
Revenues and other income:			
Oil and gas	$ 1,298,647	$ 701,780	$ 847,022
Interest and other	12,292	11,222	21,778
Gain on disposition of assets, net	1,256	4,432	7,681
	1,312,195	717,434	876,481
Costs and expenses:			
Oil and gas production	279,526	199,570	209,664
Depletion, depreciation and amortization	390,840	216,375	222,632
Exploration and abandonments	132,760	85,894	127,906
General and administrative	60,545	48,402	36,968
Accretion of discount on asset retirement obligations	5,040	-	-
Interest	91,388	95,815	131,958
Other	21,320	39,602	43,341
	981,419	685,658	772,469
Income before income taxes and cumulative effect of change in accounting principle	330,776	31,776	104,012
Income tax benefit (provision)	64,403	(5,063)	(4,016)
Income before cumulative effect of change in accounting principle	395,179	26,713	99,996
Cumulative effect of change in accounting principle, net of tax	15,413	-	-
Net income	$ 410,592	$ 26,713	$ 99,996
Net income per share:			
Basic:			
Income before cumulative effect of change in accounting principle	$ 3.37	$ .24	$ 1.01
Cumulative effect of change in accounting principle, net of tax	.13	-	-
Net income	$ 3.50	$ .24	$ 1.01
Diluted:			
Income before cumulative effect of change in accounting principle	$ 3.33	$ .23	$ 1.00
Cumulative effect of change in accounting principle, net of tax	.13	-	-
Net income	$ 3.46	$ .23	$ 1.00
Weighted average shares outstanding:			
Basic	117,185	112,542	98,529
Diluted	118,513	114,288	99,714

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

PIONEER NATURAL RESOURCES COMPANY
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(in thousands)

	Common Stock	Additional Paid-in Capital	Treasury Stock	Deferred Compensation	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss): Net Deferred Hedge Gains (Losses), Net of Tax	Accumulated Other Comprehensive Income (Loss): Investment Gains & Losses	Accumulated Other Comprehensive Income (Loss): Cumulative Translation Adjustment	Total Stockholders' Equity
Balance at January 1, 2001	$ 1,013	$ 2,352,608	$ (37,682)	$ -	$ (1,422,703)	$ -	$ 8,154	$ 3,515	$ 904,905
Common stock issued for partnership acquisitions	57	104,236	-	-	-	-	-	-	104,293
Stock options exercised and employee stock purchases	4	5,428	2,708	-	(636)	-	-	-	7,504
Purchase of treasury stock	-	-	(13,028)	-	-	-	-	-	(13,028)
Net income	-	-	-	-	99,996	-	-	-	99,996
Other comprehensive income (loss):									
Net deferred hedge gains (losses):									
Transition adjustment	-	-	-	-	-	(197,444)	-	-	(197,444)
Net deferred hedge gains	-	-	-	-	-	395,297	-	-	395,297
Tax provisions related to deferred hedge gains	-	-	-	-	-	(2,293)	-	-	(2,293)
Net hedge losses included in net income	-	-	-	-	-	5,486	-	-	5,486
Net unrealized gains (losses) on available for sale securities:									
Net unrealized available for sale securities holding losses	-	-	-	-	-	-	(45)	-	(45)
Net available for sale securities gains included in net income	-	-	-	-	-	-	(8,109)	-	(8,109)
Translation adjustment	-	-	-	-	-	-	-	(11,173)	(11,173)
Balance at December 31, 2001	1,074	2,462,272	(48,002)	-	(1,323,343)	201,046	-	(7,658)	1,285,389
Issuance of common stock	115	235,885	-	-	-	-	-	-	236,000
Adjustment to common stock issued for 2001 partnership acquisitions	-	(175)	-	-	-	-	-	-	(175)
Stock options exercised and employee stock purchases	-	416	15,783	-	(1,810)	-	-	-	14,389
Deferred compensation:									
Compensation deferred	7	16,169	-	(16,176)	-	-	-	-	-
Deferred compensation included in net income	-	-	-	1,884	-	-	-	-	1,884
Net income	-	-	-	-	26,713	-	-	-	26,713
Other comprehensive income (loss):									
Net deferred hedge gains (losses):									
Net deferred hedge losses	-	-	-	-	-	(181,628)	-	-	(181,628)
Tax benefits related to deferred hedge losses	-	-	-	-	-	2,561	-	-	2,561
Net hedge gains included in net income	-	-	-	-	-	(12,424)	-	-	(12,424)
Translation adjustment	-	-	-	-	-	-	-	2,188	2,188
Balance at December 31, 2002	1,196	2,714,567	(32,219)	(14,292)	(1,298,440)	9,555	-	(5,470)	1,374,897
Stock options exercised and employee stock purchases	1	4,100	29,183	-	-	-	-	-	33,284
Purchase of treasury stock	-	-	(2,349)	-	-	-	-	-	(2,349)
Tax benefits related to stock-based compensation	-	14,666	-	-	-	-	-	-	14,666
Deferred compensation:									
Compensation deferred	-	1,070	-	(1,070)	-	-	-	-	-
Deferred compensation included in net income	-	-	-	5,429	-	-	-	-	5,429
Net income	-	-	-	-	410,592	-	-	-	410,592
Other comprehensive income (loss):									
Net deferred hedge gains (losses), net of tax:									
Net deferred hedge losses	-	-	-	-	-	(282,165)	-	-	(282,165)
Tax benefits related to net deferred hedge losses	-	-	-	-	-	51,064	-	-	51,064
Net hedge losses included in net income	-	-	-	-	-	117,416	-	-	117,416
Translation adjustment	-	-	-	-	-	-	-	36,938	36,938
Balance at December 31, 2003	$ 1,197	$ 2,734,403	$ (5,385)	$ (9,933)	$ (887,848)	$ (104,130)	$ -	$ 31,468	$ 1,759,772

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

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2003	2002	2001
Cash flows from operating activities:			
Net income	$ 410,592	$ 26,713	$ 99,996
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation and amortization	390,840	216,375	222,632
Exploration expenses, including dry holes	97,690	64,617	103,595
Deferred income taxes	(75,588)	2,788	(7,649)
Gain on disposition of assets, net	(1,256)	(4,432)	(7,681)
Accretion of discount on asset retirement obligations	5,040	-	-
Interest related amortization	(20,610)	(5,809)	8,689
Commodity hedge related amortization	(71,816)	26,490	6,199
Cumulative effect of change in accounting principle, net of tax	(15,413)	-	-
Other noncash items	10,395	31,647	18,697
Change in operating assets and liabilities, net of effects from acquisitions:			
Accounts receivable, net	(10,983)	(23,922)	41,295
Inventories	(7,734)	3,023	(4,256)
Prepaid expenses	(5,598)	2,330	(4,328)
Other current assets, net	(602)	(4,166)	(1,976)
Accounts payable	58,603	(342)	(541)
Interest payable	(424)	48	(733)
Income taxes payable	5,928	(530)	530
Other current liabilities	(5,385)	(2,585)	1,131
Net cash provided by operating activities	763,679	332,245	475,600
Cash flows from investing activities:			
Cash acquired in acquisitions, net of fees paid	-	-	11,119
Proceeds from disposition of assets	35,698	118,850	113,453
Additions to oil and gas properties	(688,133)	(614,698)	(529,723)
Other property additions, net	(9,865)	(12,283)	(17,590)
Net cash used in investing activities	(662,300)	(508,131)	(422,741)
Cash flows from financing activities:			
Borrowings under long-term debt	264,725	529,805	328,331
Principal payments on long-term debt	(370,262)	(481,783)	(333,410)
Common stock issuance proceeds, net of issuance costs	-	236,000	-
Payment of other liabilities	(14,055)	(124,245)	(53,437)
Stock options exercised and employee stock purchases	33,020	14,389	7,504
Purchase of treasury stock	(2,349)	-	(13,028)
Deferred loan fees/debt issuance costs	(2,799)	(3,293)	-
Net cash provided by (used in) financing activities	(91,720)	170,873	(64,040)
Net increase (decrease) in cash and cash equivalents	9,659	(5,013)	(11,181)
Effect of exchange rate changes on cash and cash equivalents	1,150	(831)	(644)
Cash and cash equivalents, beginning of year	8,490	14,334	26,159
Cash and cash equivalents, end of year	$ 19,299	$ 8,490	$ 14,334

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

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in thousands)

	Year ended December 31,		
	2003	2002	2001
Net income	$ 410,592	$ 26,713	$ 99,996
Other comprehensive income (loss):			
Net deferred hedge gains (losses), net of tax:			
Transition adjustment	-	-	(197,444)
Net deferred hedge gains (losses)	(282,165)	(181,628)	395,297
Tax benefits (provisions) related to net deferred hedge (gains) losses	51,064	2,561	(2,293)
Net hedge (gains) losses included in net income	117,416	(12,424)	5,486
Net unrealized gains (losses) on available for sale securities:			
Net unrealized available for sale securities holding losses	-	-	(45)
Net available for sale securities gains included in net income	-	-	(8,109)
Translation adjustment	36,938	2,188	(11,173)
Other comprehensive income (loss)	(76,747)	(189,303)	181,719
Comprehensive income (loss)	$ 333,845	$ (162,590)	$ 281,715

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

NOTE A. Organization and Nature of Operations

Pioneer Natural Resources Company (the "Company" or "Pioneer") is a Delaware corporation whose common stock is listed and traded on the New York Stock Exchange. The Company is an oil and gas exploration and production company with ownership interests in oil and gas properties located in the United States, Argentina, Canada, South Africa, Gabon and Tunisia.

NOTE B. Summary of Significant Accounting Policies

Principles of consolidation. The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries since their acquisition or formation, and the Company's interest in the affiliated oil and gas partnerships for which it serves as general partner through certain of its wholly-owned subsidiaries. The Company proportionately consolidates less than 100 percent-owned oil and gas partnerships in accordance with industry practice. The Company owns less than a 20 percent interest in the oil and gas partnerships that it proportionately consolidates. All material intercompany balances and transactions have been eliminated.

Investments in unaffiliated equity securities that have a readily determinable fair value are classified as "trading securities" if management's current intent is to hold them for only a short period of time; otherwise, they are accounted for as "available-for-sale" securities. The Company reevaluates the classification of investments in unaffiliated equity securities at each balance sheet date. The carrying value of trading securities and available-for-sale securities are adjusted to fair value as of each balance sheet date.

Unrealized holding gains are recognized for trading securities in interest and other revenue, and unrealized holding losses are recognized in other expense during the periods in which changes in fair value occur.

Unrealized holding gains and losses are recognized for available-for-sale securities as credits or charges to stockholders' equity and other comprehensive income (loss) during the periods in which changes in fair value occur. Realized gains and losses on the divestiture of available-for-sale securities are determined using the average cost method. The Company had no investments in available-for-sale securities as of December 31, 2003 or 2002.

Investments in unaffiliated equity securities that do not have a readily determinable fair value are measured at the lower of their original cost or the net realizable value of the investment. The Company had no significant equity security investments that did not have a readily determinable fair value as of December 31, 2003 or 2002.

Use of estimates in the preparation of financial statements. Preparation of the accompanying consolidated financial statements in conformity with generally accepted accounting principles requires 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 periods. Depletion of oil and gas properties is determined using estimates of proved oil and gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluations for impairment of proved and unproved oil and gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves; commodity price outlooks; foreign laws, restrictions and currency exchange rates; and export and excise taxes.

Argentina devaluation. Early in January 2002, the Argentine government severed the direct one-to-one U.S. dollar to Argentine peso relationship that had existed for many years. As of December 31, 2003 and 2002, the Company used exchange rates of 2.93 pesos to $1 and 3.37 pesos to $1, respectively, to remeasure the peso-denominated monetary assets and liabilities of the Company's Argentine subsidiaries. The remeasurement of the peso-denominated monetary net assets of the Company's Argentine subsidiaries as of December 31, 2003 and 2002 resulted in a charge of $.3 million and $6.9 million, respectively.

As a result of certain Argentine stability laws and regulations enacted since the devaluation of the Argentine peso which impact the price the Company receives for the oil and gas it produces, the Company has continually reviewed its Argentine proved and unproved properties for impairment during 2003 and 2002. Based on estimates of future commodity prices and operating costs, the Company believes that the future cash flows from its oil and gas assets will be sufficient to fully recover its proved property basis. The Company also plans to continue its exploration efforts on all of its remaining unproved acreage. Based upon the Company's improved economic outlook for Argentina, the Company has significantly increased its capital budget for exploration and development activities in 2004 as compared to the capital budgets in 2003 and 2002.

While the Argentine economic and political situation continues to improve, the Argentine government may enact future regulations or policies that, when finalized and adopted, may materially impact, among other items, (i) the realized prices the Company receives for the commodities it produces and sells; (ii) the timing of repatriations of excess cash flow to the Company's corporate headquarters in the United States; (iii) the Company's asset valuations; (iv) the Company's level of future investments in Argentina; and (v) peso-denominated monetary assets and liabilities. While conditions are improving, numerous uncertainties exist surrounding the ultimate resolution of Argentina's economic and political stability and actual results could differ from those estimates and assumptions utilized.

New accounting pronouncements. On January 1, 2003, the Company adopted the provisions of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"). SFAS 143 amended Statement of Financial Accounting Standards No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies" ("SFAS 19") to require that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. Under the provisions of SFAS 143, asset retirement obligations are capitalized as part of the carrying value of the long-lived asset. Under the provisions of SFAS 19, asset retirement obligations were recognized using a cost-accumulation approach. Prior to the adoption of SFAS 143, the Company recorded asset retirement obligations through the unit-of-production method, except for such asset retirement obligations that were assumed in business combinations, which were recorded at their estimated fair values.

The adoption of SFAS 143 resulted in a January 1, 2003 cumulative effect adjustment to record (i) a $13.8 million increase in the carrying values of proved properties, (ii) a $26.3 million decrease in accumulated depreciation, depletion, and amortization of property, plant and equipment, (iii) a $1.0 million increase in current abandonment liabilities, (iv) a $22.4 million increase in noncurrent abandonment liabilities and (v) a $1.3 million increase in Argentine deferred income tax liabilities. The net impact of items (i) through (v) was to record a gain of $15.4 million, net of tax, as a cumulative effect adjustment of a change in accounting principle in the Company's Consolidated Statements of Operations upon adoption on January 1, 2003.

The following pro forma data summarizes the Company's net income and net income per share for the years ended December 31, 2003, 2002 and 2001 as if the Company had adopted the provisions of SFAS 143 on January 1, 2001, including aggregate pro forma asset retirement obligations on that date of $60.2 million:

	Year ended December 31,		
	2003	2002	2001
	(in thousands, except per share amounts)		
Net income, as reported	$ 410,592	$ 26,713	$ 99,996
Pro forma adjustments to reflect retroactive adoption of SFAS 143	(15,413)	4,743	1,672
Pro forma net income	$ 395,179	$ 31,456	$ 101,668
Net income per share:			
Basic - as reported	$ 3.50	$ .24	$ 1.01
Basic - pro forma	$ 3.37	$ .28	$ 1.03
Diluted - as reported	$ 3.46	$ .23	$ 1.00
Diluted - pro forma	$ 3.33	$ .28	$ 1.02

On January 1, 2003, the Company adopted the provisions of Statement of Financial Accounting Standards No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections" ("SFAS 145"). Prior to SFAS 145, gains or losses on the early extinguishment of debt were required to be classified in a company's periodic consolidated statements of operations as extraordinary gains or losses, net of associated income taxes, after the determination of income or loss from continuing operations. SFAS 145 requires, except in the case of events or transactions of a highly unusual and infrequent nature, that gains or losses from the early extinguishment of debt be classified, on both a prospective and retrospective basis, as components of a company's income or loss from continuing operations. The adoption of the provisions of SFAS 145 did not affect the Company's financial position or liquidity. Under the provisions of SFAS 145, gains or losses from the early extinguishment of debt will be recognized in the Company's Consolidated Statements of Operations as components of other income or other expense and will be included in the determination of the income (loss) from continuing operations of those periods. Accordingly, extraordinary losses from the early extinguishment of debt of $22.3 million and $3.8 million recorded during the years ended December 31, 2002 and 2001, respectively, have been reclassified to other expense.

During January 2003, the Financial Accounting Standards Board issued Interpretation No. 46, "Consolidation of Variable Interest Entities" ("FIN 46"), which requires the consolidation of certain entities that are determined to be variable interest entities ("VIEs"). An entity is considered to be a VIE when either (i) the entity lacks sufficient equity to carry on its principal operations, (ii) the equity owners of the entity cannot make decisions about the entity's activities or (iii) the entity's equity neither absorbs losses or benefits from gains.

The Company has reviewed its financial arrangements and has not identified any material VIEs that should be consolidated by the Company in accordance with FIN 46.

Cash equivalents. Cash and cash equivalents include cash on hand and depository accounts held by banks.

Inventories - equipment. Lease and well equipment to be used in future production and drilling activities are carried at the lower of cost or market, on a first-in, first-out basis. The Company has established lower of cost or market allowances to reduce the carrying values of its equipment inventories in the amounts of $.6 million and $3.6 million as of December 31, 2003 and 2002, respectively.

Inventories - commodities. Commodities are carried at the lower of average cost or market. When sold from inventory, commodities are removed on a first-in, first-out basis.

Oil and gas properties. The Company utilizes the successful efforts method of accounting for its oil and gas properties. Under this method, all costs associated with productive wells and nonproductive development wells are capitalized while nonproductive exploration costs and geological and geophysical expenditures are expensed. The Company also expenses the costs associated with exploratory wells that find oil and gas reserves if a determination that proved reserves have been found cannot be made within one year of the exploration well being drilled unless other drilling or exploration activities to evaluate the discovery are firmly planned. The Company capitalizes interest on expenditures for significant development projects until such projects are ready for their intended use.

The Company owns interests in 11 natural gas processing plants and five treating facilities. The Company operates seven of the plants and all five treating facilities. The Company's ownership in the natural gas processing plants and treating facilities is primarily to accommodate handling the Company's gas production and thus are considered a component of the capital and operating costs of the respective fields that they service. To the extent that there is excess capacity at a plant or treating facility, the Company attempts to process third party gas volumes for a fee to keep the plant or treating facility at capacity. All revenues and expenses derived from third party gas volumes processed through the plants and treating facilities are reported as components of oil and gas production costs. The third party revenues generated from the plant and treating facilities for the three years ended December 31, 2003, 2002 and 2001 were $39.5 million, $28.4 million and $32.7 million, respectively. The third party expenses attributable to the plants and treating facilities for the same respective periods were $11.3 million, $9.3 million and $9.7 million. The capitalized costs of the plants and treating facilities are included in proved oil and gas properties and are depleted using the unit-of-production method along with the other capitalized costs of the field that they service.

Capitalized costs relating to proved properties are depleted using the unit-of-production method based on proved reserves. Costs of significant nonproducing properties, wells in the process of being drilled and development projects are excluded from depletion until such time as the related project is completed and proved reserves are established or, if unsuccessful, impairment is determined.

Capitalized costs of individual properties sold or abandoned are charged to accumulated depletion, depreciation and amortization with the proceeds from the sales of individual properties credited to property costs. No gain or loss is recognized until the entire amortization base is sold. However, gain or loss is recognized from the sale of less than an entire amortization base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base.

The Company reviews its long-lived assets to be held and used, including proved oil and gas properties accounted for under the successful efforts method of accounting, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected future cash flows is less than the carrying amount of the assets. In this circumstance, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset.

Unproved oil and gas properties that are individually significant are periodically assessed for impairment by comparing their cost to their estimated value on a project-by-project basis. The estimated value is affected by the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, the Company will recognize an impairment loss at that time by recording an allowance. The remaining unproved oil and gas properties, if any, are aggregated and an overall impairment allowance is provided based on the Company's historical experience.

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

Environmental. The Company's environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Expenditures that extend the life of the related property or mitigate or prevent future environmental contamination are capitalized. Liabilities are recorded when environmental assessment and/or remediation is probable and the costs can be reasonably estimated. Such liabilities are undiscounted unless the timing of cash payments for the liability are fixed or reliably determinable.

Revenue recognition. The Company uses the entitlements method of accounting for oil, NGL and gas revenues. Sales proceeds in excess of the Company's entitlement are included in other liabilities and the Company's share of sales taken by others is included in other assets in the accompanying Consolidated Balance Sheets. The following table presents the Company's entitlement assets and entitlement liabilities and their associated volumes as of December 31, 2003 and 2002 ($ in millions):

	December 31,			
	2003		2002	
	Amount	MMcf	Amount	MMcf
Entitlement assets	$ 10.5	3,929	$ 9.7	4,240
Entitlement liabilities	$ 15.8	14,793	$ 15.1	14,302

Derivatives and hedging. In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133") as amended, the provisions of which the Company adopted effective January 1, 2001.

SFAS 133 requires the accounting recognition of all derivative instruments as either assets or liabilities at fair value. Derivative instruments that are not hedges must be adjusted to fair value through net income (loss). Under the provisions of SFAS 133, changes in the fair value of derivative instruments that are fair value hedges are offset against changes in the fair value of the hedged assets, liabilities, or firm commitments through net income (loss). Effective changes in the fair value of derivative instruments that are cash flow hedges are recognized in "accumulated other comprehensive income (loss) ("AOCI") - net deferred hedge gains (losses), net of tax" in the stockholders' equity section of the Company's Consolidated Balance Sheets until such time as the hedged items are recognized in net income (loss). Ineffective portions of a derivative instrument's change in fair value are immediately recognized in net income (loss).

The adoption of SFAS 133 resulted in a January 1, 2001 transition adjustment to (i) reclassify $57.8 million of deferred losses on terminated hedge positions from other assets (including $11.6 million of other current assets), (ii) increase other current assets, other assets and other current liabilities by $7.0 million, $6.2 million and $146.6 million, respectively, to record the fair value of open hedge derivatives, (iii) increase the carrying value of hedged long-term debt by $6.2 million and (iv) reduce stockholders' equity by $197.4 million for the net impact of items (i) through (iii) above. The $197.4 million reduction in stockholders' equity was reflected as a transition adjustment in other comprehensive income (loss) on January 1, 2001.

Under the provisions of SFAS 133, the Company may designate a derivative instrument as hedging the exposure to changes in the fair value of an asset or a liability or an identified portion thereof that is attributable to a particular risk (a "fair value hedge") or as hedging the exposure to variability in expected future cash flows that are attributable to a particular risk (a "cash flow hedge"). Both at the inception of a hedge and on an ongoing basis, a fair value hedge must be expected to be highly effective in achieving offsetting changes in fair value attributable to the hedged risk during the periods that a hedge is designated. Similarly, a cash flow hedge must be expected to be highly effective in achieving offsetting cash flows attributable to the hedged risk during the term of the hedge. The expectation of hedge effectiveness must be supported by matching the essential terms of the hedged asset, liability or forecasted transaction to the derivative hedge contract or by effectiveness assessments using statistical measurements. The Company's policy is to assess actual hedge effectiveness at the end of each calendar quarter.

See Note J for a description of the specific types of derivative transactions in which the Company participates.

Stock-based compensation. The Company has a long-term incentive plan (the "Long-Term Incentive Plan") under which the Company grants stock-based compensation. The Long-Term Incentive Plan is described more fully in Note G. The Company accounts for stock-based compensation granted under the Long-Term Incentive Plan using the intrinsic value method prescribed by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" ("APB 25") and related interpretations. Stock-based compensation expenses associated with option grants were not recognized in the Company's net income during the years ended December 31, 2003, 2002 and 2001, as all options granted under the Long-Term Incentive Plan had exercise prices equal to the market value of the underlying common stock on the dates of grant. Stock-based compensation expense associated with restricted stock awards is deferred and amortized to earnings ratably over the vesting periods of the awards. The following table illustrates the pro forma effect on net income and earnings per share as if the Company had applied the fair value recognition provisions of Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" to stock-based compensation during the years ended December 31, 2003, 2002 and 2001:

	Year ended December 31,		
	2003	2002	2001
	(in thousands, except per share amounts)		
Net income, as reported	$ 410,592	$ 26,713	$ 99,996
Plus: Total stock-based employee compensation expense included in net income for all awards, net of tax (a)	3,447	1,884	-
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of tax (a)	(11,429)	(11,691)	(6,533)
Pro forma net income	$ 402,610	$ 16,906	$ 93,463
Net income per share:			
Basic - as reported	$ 3.50	$ .24	$ 1.01
Basic - pro forma	$ 3.44	$ .15	$ .95
Diluted - as reported	$ 3.46	$ .23	$ 1.00
Diluted - pro forma	$ 3.40	$ .15	$ .94

(a) Total stock-based employee compensation expense included in net income is net of a tax benefit of $2.0 million during the year ended December 31, 2003. Total stock-based employee compensation expense determined under the fair value based method for the year ended December 31, 2003 is net of a $4.6 million tax benefit. No tax benefits were recognized for the pro forma compensation expense amounts during the years ended December 31, 2002 or 2001. See Note P for additional information regarding the Company's income taxes.

Foreign currency translation. The U.S. dollar is the functional currency for all of the Company's international operations except Canada. Accordingly, monetary assets and liabilities denominated in a foreign currency are remeasured to U.S. dollars at the exchange rate in effect at the end of each reporting period; revenues and costs and expenses denominated in a foreign currency are remeasured at the average of the exchange rates that were in effect during the period in which the revenues and costs and expenses were recognized. The resulting gains or losses from remeasuring foreign currency denominated balances into U.S. dollars are recorded in other income or other expense, respectively. Nonmonetary assets and liabilities denominated in a foreign currency are remeasured at the historic exchange rates that were in effect when the assets or liabilities were acquired or incurred.

The functional currency of the Company's Canadian operations is the Canadian dollar. The financial statements of the Company's Canadian subsidiary entities are translated to U.S. dollars as follows: all assets and liabilities are translated using the exchange rate in effect at the end of each reporting period; revenues and costs and expenses are translated using the average of the exchange rates that were in effect during the period in which the revenues and costs and expenses were recognized. The resulting gains or losses from translating non-U.S. dollar denominated balances are recorded in the accompanying Consolidated Statements of Stockholders' Equity for the period through accumulated other comprehensive income (loss).

The following table presents the exchange rates used to translate the financial statements of the Company's Canadian subsidiary in the preparation of the consolidated financial statements as of and for the years ended December 31, 2003, 2002 and 2001:

	December 31,		
	2003	2002	2001
U.S. Dollar from Canadian Dollar - Balance Sheets	.7710	.6362	.6277
U.S. Dollar from Canadian Dollar - Statements of Operations	.7161	.6371	.6356

Reclassifications. Certain reclassifications have been made to the 2002 and 2001 amounts in order to conform with the 2003 presentation.

NOTE C. Disclosures About Fair Value of Financial Instruments

The following table presents the carrying amounts and estimated fair values of the Company's financial instruments as of December 31, 2003 and 2002:

	2003		2002	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in thousands)			
Derivative contract assets (liabilities):				
Commodity price hedges	$ (201,422)	$ (201,422)	$ (108,837)	$ (108,837)
Unrealized terminated commodity price hedges	$ (1,490)	$ (1,490)	$ 512	$ 512
Btu swap contracts	$ (6,856)	$ (6,856)	$ (13,363)	$ (13,363)
Foreign currency contracts	$ -	$ -	$ 15	$ 15
Financial assets:				
Trading securities	$ 7,596	$ 7,596	$ 5,144	$ 5,144
5-1/2% note receivable due 2008	$ 2,086	$ 2,086	$ 2,247	$ 2,283
Financial liabilities - long-term debt:				
Line of credit	$ (160,000)	$ (160,000)	$ (260,000)	$ (260,000)
8-7/8% senior notes due 2005	$ (135,239)	$ (141,426)	$ (146,704)	$ (147,318)
8-1/4% senior notes due 2007	$ (155,253)	$ (171,188)	$ (161,130)	$ (164,925)
6-1/2% senior notes due 2008	$ (354,497)	$ (378,725)	$ (362,592)	$ (359,205)
9-5/8% senior notes due 2010	$ (350,558)	$ (424,385)	$ (338,197)	$ (406,901)
7-1/2% senior notes due 2012	$ (150,000)	$ (162,990)	$ (150,000)	$ (160,635)
7-1/5% senior notes due 2028	$ (249,914)	$ (270,312)	$ (249,913)	$ (245,025)

Cash and cash equivalents, accounts receivable, other current assets, accounts payable, interest payable and other current liabilities. The carrying amounts approximate fair value due to the short maturity of these instruments.

Commodity price swap and collar contracts, interest rate swaps and foreign currency swap contracts. The fair value of commodity price swap and collar contracts, interest rate swaps and foreign currency contracts are estimated from quotes provided by the counterparties to these derivative contracts and represent the estimated amounts that the Company would expect to receive or pay to settle the derivative contracts. During the year ended December 31, 2003, the Company terminated all of its interest rate swap contracts and the foreign currency contracts matured. See Note J for a description of each of these derivatives, including whether the derivative contract qualifies for hedge accounting treatment or is considered a speculative derivative contract.

Financial assets. As of December 31, 2002, the Company had an investment in bonds that were classified as trading securities and a note receivable. The Company divested the bonds during January 2003. The fair value of the 5-1/2 percent note receivable was determined based on underlying market rates of interest.

Long-term debt. The carrying amount of borrowings outstanding under the Company's corporate credit facility approximates fair value because these instruments bear interest at variable market rates. The fair values of each of the senior note issuances were determined based on quoted market prices for each of the issues. See Note E for additional information regarding the Company's long-term debt.

NOTE D. Acquisitions

Falcon acquisitions. During the year ended December 31, 2002, the Company purchased, through two transactions, an additional 30 percent working interest in the Falcon field development and a 25 percent working interest in associated acreage in the deepwater Gulf of Mexico for a combined purchase price of $61.1 million. As a result of these transactions, the Company owned a 75 percent working interest in and operated the Falcon field development and related exploration blocks at December 31, 2002. On March 28, 2003, the Company purchased the remaining 25 percent working interest that it did not already own in the Falcon field, the Harrier field and surrounding satellite prospects in the deepwater Gulf of Mexico for $120.4 million, including $114.1 million of cash, $1.7 million of asset retirement obligations assumed and $4.6 million of closing adjustments.

West Panhandle acquisitions. During July 2002, the Company completed the purchase of the remaining 23 percent of the rights that the Company did not already own in its core area West Panhandle gas field, 100 percent of the West Panhandle reserves attributable to field fuel, 100 percent of the related West Panhandle field gathering system and ten blocks surrounding the Company's deepwater Gulf of Mexico Falcon discovery. In connection with these transactions, the Company recorded $100.4 million to proved oil and gas properties, $3.8 million to unproved oil and gas properties and $1.9 million to assets held for resale; retired a capital cost obligation for $60.8 million; settled a $20.9 million gas balancing receivable; assumed trade and environmental obligations amounting to $5.8 million in the aggregate; and paid $140.2 million of cash. The capital cost obligation retired by the Company for $60.8 million represented an obligation for West Panhandle gas field capital additions that was not able to be prepaid and bore interest at an annual rate of 20 percent. The portion of the purchase price allocated to the retirement of the capital cost obligation was based on a discounted cash flow analysis using a market discount rate for obligations with similar terms. The capital cost obligation had a carrying value of $45.2 million, resulting in a loss of $15.6 million from the early extinguishment of this obligation.

Affiliated partnership mergers. During 2001, the limited partners of 42 of the Company's affiliated partnerships approved an agreement and plan of merger ("Plan of Merger") among the Company, Pioneer Natural Resources USA, Inc. ("Pioneer USA"), a wholly-owned subsidiary of the Company, and the partnerships. The Plan of Merger was accounted for as a purchase business combination. In consideration for the partnerships' net assets, the limited partners received 5.7 million shares of the Company's common stock valued at $18.35 per share. In connection with this transaction, the Company recorded $92.9 million to proved oil and gas properties, $13.6 million to cash and $.3 million to other net assets. The cash acquired from the partnerships, net of $2.5 million of cash transaction costs, is included in "cash acquired in acquisitions, net of fees paid" in the accompanying Consolidated Statement of Cash Flows for the year ended December 31, 2001. Except for the cash acquired, this transaction represents a noncash investing activity of the Company that was funded by the issuance of common stock.

Other acquisitions. During 2003, in addition to the incremental 25 percent working interest acquired in the Falcon area, the Company spent $30.6 million to acquire producing properties in the Spraberry field and unproved properties in Alaska, the Gulf of Mexico, Argentina, Canada and Tunisia. During 2002, in addition to the Falcon and West Panhandle acquisitions referred to above, the Company spent $25.5 million to acquire additional unproved acreage in the United States, including 34 Gulf of Mexico shelf blocks, six deepwater Gulf of Mexico blocks, a 70 percent working interest in ten state leases on Alaska's North Slope and property interests in other areas of the United States. Also during 2002, the Company acquired unproved and proved oil and gas property interests in Canada for $2.3 million and $.5 million, respectively, and $1.8 million of additional unproved property interests in Tunisia. During 2001, the Company spent $77.9 million to acquire additional working interests in the Gulf of Mexico Aconcagua discovery, the related Canyon Express gathering system and the Devils Tower project; 21 deepwater Gulf of Mexico blocks; 250,000 acres in the Anticlinal Campamento, Dos Hermanas and La Calera areas of the Neuquen Basin in Argentina; and a 30 percent interest in the Anaguid permit in the Ghadames basin onshore Southern Tunisia.

NOTE E. Long-term Debt

Long-term debt, including the effects of fair value hedges and discounts, consisted of the following components at December 31, 2003 and 2002:

	December 31, 2003	December 31, 2002
	(in thousands)	
Lines of credit	$ 160,000	$ 260,000
8-7/8% senior notes due 2005	135,239	146,704
8-1/4% senior notes due 2007	155,253	161,130
6-1/2% senior notes due 2008	354,497	362,592
9-5/8% senior notes due 2010	350,558	338,197
7-1/2% senior notes due 2012	150,000	150,000
7-1/5% senior notes due 2028	249,914	249,913
Total long-term debt	$ 1,555,461	$ 1,668,536

Maturities of long-term debt at December 31, 2003 are as follows (in thousands):

2004	$ -
2005	$ 135,239
2006	$ -
2007	$ 155,253
2008	$ 514,497
Thereafter	$ 750,472

Lines of credit. During December 2003, the Company entered into a new five-year unsecured revolving credit agreement (the "New Credit Facility") that matures in December 2008. The New Credit Facility replaced the Company's $575 million revolving credit facility (the "Prior Credit Facility") that had a scheduled maturity in March 2005. The terms of the New Credit Facility provide for initial aggregate loan commitments of $700 million from a syndication of participating banks (the "Lenders"). Aggregate loan commitments under the New Credit Facility may be increased to a maximum aggregate amount of $1 billion if the Lenders increase their loan commitments or loan commitments of new financial institutions are added to the New Credit Facility.

Borrowings under the New Credit Facility may be in the form of revolving loans or swing line loans. Aggregate outstanding swing line loans may not exceed $80 million. Revolving loans issued under the New Credit Facility bear interest, at the option of the Company, based on (a) a rate per annum equal to the higher of the prime rate announced from time to time by JPMorgan Chase Bank (4.0 percent per annum at December 31, 2003) or the weighted average of the rates on overnight Federal funds transactions with members of the Federal Reserve System during the last preceding business day plus 50 basis point (1.5 percent per annum at December 31, 2003) or (b) a base Eurodollar rate, substantially equal to LIBOR (1.2 percent per annum at December 31, 2003), plus a margin that is based on a grid of the Company's debt rating (125 basis points per annum at December 31, 2003). Swing line loans bear interest at a rate per annum equal to the ASK rate for Federal funds periodically published by the Dow Jones Market Service. As of December 31, 2003, the Company had $160 million of Eurodollar rate revolving loans outstanding under the New Credit Facility.

Advances under the Prior Credit Facility bore interest, at the option of the Company, based on (a) a base rate equal to the higher of the Bank of America, N.A. prime rate or a rate per annum based on the weighted average of the rates on overnight Federal funds transactions with members of the Federal Reserve System, plus 50 basis points; plus a eurodollar margin less 125 basis points, (b) a Eurodollar rate, substantially equal to LIBOR, plus a eurodollar margin, or (c) a fixed rate (for aggregate advances not exceeding $50 million) as quoted by the banks pursuant to a request by the Company.

The New Credit Facility imposes certain restrictive covenants on the Company, including the maintenance of a ratio of the Company's earnings before gain or loss on the disposition of assets, interest expense, income taxes, depreciation, depletion and amortization expense, exploration and abandonments expense and other noncash charges and expenses to consolidated interest expense of at least 3.5 to 1.0; maintenance of a ratio of total debt to book capitalization less intangible assets (other than intangible oil and gas assets), accumulated other comprehensive income and certain noncash asset write-downs not to exceed .60 to 1.0; and, maintenance of an annual ratio of the net present value of the Company's oil and gas properties to total debt of at least 1.25 to 1.00 until the Company has an investment grade rating. The Company was in compliance with all of its debt covenants as of December 31, 2003.

As of December 31, 2003 and 2002, the Company had $47.6 million and $45.4 million of undrawn letters of credit, respectively, of which $28.8 million on December 31, 2003 and $27.2 million on December 31, 2002 were undrawn commitments under the New Credit Facility and Prior Credit Facility, respectively. As of December 31, 2003 and 2002, the Company had unused borrowing capacity of $511.2 million and $287.8 million under the New Credit Facility and Prior Credit Facility, respectively.

Senior notes. The Company's senior notes are general unsecured obligations ranking equally in right of payment with all other senior unsecured indebtedness of the Company and are senior in right of payment to all existing and future subordinated indebtedness of the Company. The Company is a holding company that conducts all of its operations through subsidiaries; consequently, the senior notes are structurally subordinated to all obligations of its subsidiaries. Interest on the Company's senior notes is payable semi-annually. Pioneer USA has fully and unconditionally guaranteed the senior note issuances. See Note S for a discussion of Pioneer USA debt guarantees and Consolidating Financial Statements.

During April 2002, the Company issued $150.0 million of 7-1/2 percent senior notes due April 15, 2012 (the "7-1/2 percent senior notes"). The 7-1/2 percent senior notes were issued at a price equal to 100 percent of their principal amount and resulted in net proceeds to the Company, after underwriting discounts, commissions and costs of issuance, of $146.7 million. The net proceeds from the issuance of the 7-1/2 percent senior notes were used to reduce outstanding borrowings under the Prior Credit Facility. The 7-1/2 percent senior notes and 9-5/8 percent senior notes contain various restrictive covenants, including restrictions on the incurrence of additional indebtedness and certain payments defined within the associated indenture. The Company was in compliance with all of its senior note covenants as of December 31, 2003.

As of December 31, 2003 and 2002, the aggregate carrying value of the Company's 8-7/8, 8-1/4, 6-1/2 and 9-5/8 percent senior notes included $27.4 million and $35.7 million, respectively, of incremental carrying value attributable to the unamortized net deferred hedge gains realized from terminated fair value hedge interest rate swap contracts. See Note J for additional information regarding terminated fair value hedge interest rate swap contracts.

Early extinguishment of debt and capital cost obligation. During 2003, the Company repurchased $5.1 million of its 8-7/8 percent senior notes and repaid the Prior Credit Facility prior to its scheduled maturity. The Company recognized $1.5 million of charges to other expense associated with the aforementioned debt extinguishments.

During 2002, the Company repurchased $47.1 million of the 9-5/8 percent senior notes, $13.9 million of the 8-7/8 percent senior notes and repaid a $45.2 million capital cost obligation. The Company recognized a charge to other expense of $22.3 million associated with these debt extinguishments.

During 2001, the Company redeemed the remaining $22.5 million of 11-5/8 percent senior subordinated discount notes and $6.8 million of 10-5/8 percent senior subordinated notes. Additionally, the Company repurchased $38.7 million of the 9-5/8 percent senior notes. Associated with these debt extinguishments, the Company recognized a charge to other expense of $3.8 million.

See Note B for a discussion of the classification of gains and losses on the early extinguishment of debt after the adoption of SFAS 145 on January 1, 2003.

Interest expense. The following amounts have been incurred and charged to interest expense for the years ended December 31, 2003, 2002 and 2001:

	Year Ended December 31,		
	2003	2002	2001
		(in thousands)	
Cash payments for interest	$ 117,870	$ 113,827	$ 129,992
Accretion/amortization of discounts or premiums on loans	2,873	5,488	7,937
Amortization of deferred hedge gains (see Note J)	(26,114)	(14,108)	(2,750)
Amortization of capitalized loan fees	2,528	2,436	2,252
Kansas ad valorem tax (see Note I)	103	375	1,250
Net change in accruals	(424)	48	(732)
Interest incurred	96,836	108,066	137,949
Less interest capitalized	(5,448)	(12,251)	(5,991)
Total interest expense	$ 91,388	$ 95,815	$ 131,958

NOTE F. Related Party Transactions

Activities with affiliated partnerships. Prior to 1992, the Company, through its wholly-owned subsidiaries, sponsored 44 drilling partnerships and three public income partnerships, all of which were formed primarily for the purpose of drilling and completing wells or acquiring producing properties. During 2001, the Company completed the merger of 42 of the limited partnerships into Pioneer USA. See Note D for additional information regarding the mergers.

The Company, through a wholly-owned subsidiary, serves as operator of properties in which it and its affiliated partnerships have an interest. Accordingly, the Company receives producing well overhead, drilling well overhead and other fees related to the operation of the properties. The affiliated partnerships also reimburse the Company for their allocated share of general and administrative charges.

The activities with affiliated partnerships are summarized for the following related party transactions for the years ended December 31, 2003, 2002 and 2001:

	2003	2002	2001
		(in thousands)	
Receipt of lease operating and supervision charges in accordance with standard industry operating agreements	$ 1,473	$ 1,495	$ 9,281
Reimbursement of general and administrative expenses	$ 148	$ 127	$ 1,265

NOTE G. Incentive Plans

Retirement Plans

Deferred compensation retirement plan. In August 1997, the Compensation Committee of the Board of Directors approved a deferred compensation retirement plan for the officers and certain key employees of the Company. Each officer and key employee is allowed to contribute up to 25 percent of their base salary and 100 percent of their annual bonus. The Company will provide a matching contribution of 100 percent of the officer's and key employee's contribution limited to the first 10 percent of the officer's base salary and eight percent of the key employee's base salary. The Company's matching contribution vests immediately. A trust fund has been established by the Company to accumulate the contributions made under this retirement plan. The Company's matching contributions were $851 thousand, $805 thousand and $652 thousand for the years ended December 31, 2003, 2002 and 2001, respectively.

401(k) plan. The Pioneer Natural Resources USA, Inc. 401(k) and Matching Plan (the "401(k) Plan") is a defined contribution plan established under the Internal Revenue Code Section 401. The 401(k) Plan was formed by the merger of the Pioneer Natural Resources USA, Inc. 401(k) Plan and the Pioneer Natural Resources USA, Inc. Matching Plan on January 1, 2002. All regular full-time and part-time employees of Pioneer USA are eligible to participate in the 401(k) Plan on the first day of the month following their date of hire. Participants may contribute an amount of not less than two percent nor more than 30 percent of their annual salary into the 401(k) Plan. Matching contributions are made to the 401(k) Plan in cash by Pioneer USA in amounts equal to 200 percent of a participant's contributions to the 401(k) Plan that are not in excess of five percent of the participant's basic compensation (the "Matching Contribution"). Each participant's account is credited with the participant's contributions, their Matching Contributions and allocations of the 401(k) Plan's earnings. Participants are fully vested in their account balances except for Matching Contributions and their proportionate share of 401(k) Plan earnings attributable to Matching Contributions, which proportionately vest over a four year period that begins with the participant's date of hire. During the years ended December 31, 2003, 2002 and 2001, the Company recognized compensation expense of $4.5 million, $4.1 million and $3.4 million, respectively, as a result of Matching Contributions.

Long-Term Incentive Plan

In August 1997, the Company's stockholders approved a Long-Term Incentive Plan which provides for the granting of incentive awards in the form of stock options, stock appreciation rights, performance units and restricted stock to directors, officers and employees of the Company. The Long-Term Incentive Plan provides for the issuance of a maximum number of shares of common stock equal to 10 percent of the total number of shares of common stock equivalents outstanding less the total number of shares of common stock subject to outstanding awards under any stock-based plan for the directors, officers or employees of the Company.

The following table calculates the number of shares or options available for grant under the Company's Long-Term Incentive Plan as of December 31, 2003 and 2002:

	December 31,	
	2003	2002
Shares outstanding	119,287,772	117,252,538
Outstanding options exercisable or exercisable within 60 days	3,279,024	5,024,173
	122,566,796	122,276,711
Maximum shares/options allowed under the Long-Term Incentive Plan	12,256,680	12,227,671
Less: Outstanding awards under the Long-Term Incentive Plan	(5,534,037)	(7,432,414)
Outstanding options under predecessor incentive plans	(417,052)	(488,671)
Shares/options available for future grant	6,305,591	4,306,586

Stock option awards. The Company has a program of awarding semi-annual stock options to its officers and employees and gives its non-employee directors a choice to receive (i) 100 percent restricted stock, (ii) 100 percent stock options, (iii) 100 percent cash, or (iv) a combination of 50/50 of any two, as their annual compensation. This program provides for stock option awards at an exercise price based upon the closing sales price of the Company's common stock on the day prior to the date of grant. Employee stock option awards vest over an 18 month or three-year schedule and provide a five-year exercise period from each vesting date. Non-employee directors' stock options vest quarterly and provide for a five-year exercise period from each vesting date. The Company granted 1,353,988, 1,643,212 and 1,627,071 options under the Long-Term Incentive Plan during the years ended December 31, 2003, 2002 and 2001, respectively.

Restricted stock awards. During the year ended December 31, 2003, the Company issued 77,625 restricted shares of the Company's common stock. The restricted share awards were issued as compensation to directors, officers and key employees of the Company. The restricted share awards included 4,425 shares that were granted to directors of the Company on May 14, 2003. Director awards vest on a quarterly prorata basis during the year ended May 14, 2004. The remaining 73,200 restricted shares were awarded to officers and key employees of the Company. Of the shares awarded, 9,500 shares vest on January 26, 2006 and the remaining 63,700 shares vest on September 30, 2006.

During the year ended December 31, 2002, the Company issued 654,445 restricted shares of the Company's common stock. The restricted share awards were issued as compensation to directors, officers and key employees of the Company. The restricted share awards included 18,545 shares that were granted to directors of the Company on May 13, 2002. Director awards for 3,302 shares vested on a quarterly prorata basis during the year ended May 13, 2003 and director awards for 15,243 shares vest on May 13, 2005. The remaining 635,900 restricted shares were awarded to officers and key employees of the Company on August 12, 2002 and vest on August 12, 2005.

The Company recorded $1.1 million and $16.2 million of deferred compensation associated with restricted stock awards in the stockholders' equity section of the accompanying Consolidated Balance Sheets during the years ended December 31, 2003 and 2002, respectively. Such amounts will be amortized to compensation expense over the vesting periods of the awards. During the years ended December 31, 2003 and 2002, amortization of the restricted stock awards increased the Company's compensation expense by $5.4 million and $1.9 million, respectively.

The following table reflects the outstanding restricted stock awards and activity related thereto as of and for the years ended December 31, 2003 and 2002:

	Year Ended December 31, 2003		Year Ended December 31, 2002	
	Number of Shares	Weighted Average Price	Number of Shares	Weighted Average Price
Restricted Stock Awards:				
Restricted shares outstanding at beginning of year	652,793	$ 24.72	-	$ -
Shares granted	77,625	$ 25.39	654,445	$ 24.72
Shares forfeited	(36,500)	$ 24.72	-	$ -
Lapse of restrictions	(16,945)	$ 25.59	(1,652)	$ 24.60
Restricted shares outstanding at end of year	676,973	$ 24.79	652,793	$ 24.72

There were no restricted stock awards to directors or employees during the year ended December 31, 2001.

Other stock based plans. Prior to the formation of the Company in 1997, the Company's predecessor companies had long-term incentive plans in place that allowed the predecessor companies to grant incentive awards similar to the provisions of the Long-Term Incentive Plan. Upon formation of the Company, all awards under these plans were assumed by the Company with the provision that no additional awards be granted under the predecessor plans.

SFAS 123 disclosures. The Company applies APB 25 and related interpretations in accounting for its stock option awards. Accordingly, no compensation expense has been recognized for its stock option awards. If compensation expense for the stock option awards had been determined consistent with SFAS 123, the Company's net income and net income per share would have been less than the reported amounts. See Note B for a comparison of net income and net income per share as reported and as adjusted for the pro forma effects of determining compensation expense in accordance with SFAS 123.

Under SFAS 123, the fair value of each stock option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used for grants during the years ended December 31, 2003, 2002 and 2001:

	Year Ended December 31,		
	2003	2002	2001
Risk-free interest rate	3.06%	2.80%	4.13%
Expected life	5 years	5 years	5 years
Expected volatility	36%	45%	49%
Expected dividend yield	-	-	-

A summary of the Company's stock option plans as of December 31, 2003, 2002 and 2001, and changes during the years then ended, are presented below:

	Year Ended December 31, 2003		Year Ended December 31, 2002		Year Ended December 31, 2001	
	Number of Shares	Weighted Average Price	Number of Shares	Weighted Average Price	Number of Shares	Weighted Average Price
Non-statutory stock options:						
Outstanding, beginning of year . . .	7,268,292	$ 19.60	6,926,071	$ 18.16	6,510,559	$ 18.10
Options granted	1,353,988	$ 24.84	1,643,212	$ 21.14	1,627,071	$ 18.29
Options forfeited	(1,286,370)	$ 29.22	(154,717)	$ 26.27	(566,189)	$ 25.83
Options exercised	(2,061,794)	$ 15.68	(1,146,274)	$ 12.19	(645,370)	$ 11.14
Outstanding, end of year	5,274,116	$ 20.13	7,268,292	$ 19.60	6,926,071	$ 18.16
Exercisable at end of year	2,581,256	$ 17.56	4,269,659	$ 20.15	4,005,762	$ 20.82
Weighted average fair value of options granted during the year	$ 8.95		$ 8.87		$ 8.65	

The following table summarizes information about the Company's stock options outstanding and options exercisable at December 31, 2003:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at December 31, 2003	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at December 31, 2003	Weighted Average Exercise Price
$ 5-11	432,765	2.8 years	$ 8.70	432,765	$ 8.70
$ 12-18	2,343,782	4.3 years	$ 17.10	1,431,111	$ 16.34
$ 19-26	2,327,499	5.4 years	$ 24.55	547,310	$ 23.72
$ 27-30	139,358	1.6 years	$ 28.44	139,358	$ 28.44
$ 31-43	30,712	3.1 years	$ 40.06	30,712	$ 40.06
	5,274,116			2,581,256	

Employee Stock Purchase Plan

The Company has an Employee Stock Purchase Plan (the "ESPP") that allows eligible employees to annually purchase the Company's common stock at a discounted price. Officers of the Company are not eligible to participate in the ESPP. Contributions to the ESPP are limited to 15 percent of an employee's pay (subject to certain ESPP limits) during the nine month offering period. Participants in the ESPP purchase the Company's common stock at a price that is 15 percent below the closing sales price of the Company's common stock on either the first day or the last day of each offering period, whichever closing sales price is lower.

Postretirement Benefit Obligations

As of December 31, 2003 and 2002, the Company had recorded $15.6 million and $19.7 million, respectively, of unfunded accumulated postretirement benefit obligations in the Company's accompanying Consolidated Balance Sheets. These obligations are comprised of five plans of which four relate to predecessor entities that the Company acquired in prior years. These plans had no assets as of December 31, 2003 or 2002. Other than the Company's retirement plan, the participants of these plans are not current employees of the Company.

The accumulated postretirement benefit obligations pertaining to these plans were determined by independent actuaries for four plans representing $11.2 million of unfunded accumulated postretirement benefit obligations as of December 31, 2003 and by the Company for one plan representing $4.4 million of unfunded accumulated postretirement benefit obligations as of December 31, 2003. Interest costs at an annual rate of six percent of the periodic undiscounted accumulated postretirement benefit obligations were employed in the valuations of the benefit obligations. Certain of the aforementioned plans provide for medical and dental cost subsidies for plan participants. Annual medical cost escalation trends of 12 percent in 2004, declining to five percent in 2011 and thereafter, and annual dental cost escalation trends of 7.5 percent in 2004, declining to five percent in 2009 and thereafter, were employed to estimate the accumulated postretirement benefit obligations associated with the medical and dental cost subsidies.

The following table reconciles changes in the Company's unfunded accumulated postretirement benefit obligations during the years ended December 31, 2003, 2002 and 2001:

	Year Ended December 31,		
	2003	2002	2001
		(in thousands)	
Beginning accumulated postretirement benefit obligations	$ 19,743	$ 19,750	$ 20,064
Benefit payments	(1,472)	(1,702)	(2,009)
Service costs	205	205	205
Net actuarial gains	(4,410)	-	-
Accretion of discounts	1,490	1,490	1,490
Ending accumulated postretirement benefit obligations	$ 15,556	$ 19,743	$ 19,750

Estimated benefit payments and service costs associated with the plans for the year ended December 31, 2004 are $1.4 million and $.3 million, respectively.

NOTE H. Issuance of Common Stock

During April 2002, the Company completed a public offering of 11.5 million shares of its common stock at $21.50 per share. Associated therewith, the Company received $236.0 million of net proceeds after the payment of issuance costs. The Company used the net proceeds from the public offering to fund the 2002 acquisition of Falcon assets and associated acreage in the deepwater Gulf of Mexico and the West Panhandle gas field acquisitions. See Note D for information regarding these acquisitions.

NOTE I. Commitments and Contingencies

Severance agreements. The Company has entered into severance agreements with its officers, subsidiary company officers and certain key employees. Salaries and bonuses for the Company's officers are set by the Company's board of directors for the parent company officers and by the Company's management committee for subsidiary company officers and key employees. The Company's board of directors and management committee can grant increases or reductions to base salary at their discretion. The current annual salaries for the parent company officers, the subsidiary company officers and key employees covered under such agreements total approximately $19.9 million.

Indemnifications. The Company has indemnified its directors and certain of its officers, employees and agents with respect to claims and damages arising from acts or omissions taken in such capacity, as well as with respect to certain litigation.

Legal actions. The Company is party to various legal actions incidental to its business, including, but not limited to, the proceedings described below. The majority of these lawsuits primarily involve claims for damages arising from oil and gas leases and ownership interest disputes. The Company believes that the ultimate disposition of these legal actions will not have a material adverse effect on the Company's consolidated financial position, liquidity, capital resources or future results of operations. The Company will continue to evaluate its litigation matters on a quarter-by-quarter basis and will adjust its litigation reserves as appropriate to reflect the then current status of litigation.

Alford. The Company is party to a 1993 class action lawsuit filed in the 26th Judicial District Court of Stevens County, Kansas by two classes of royalty owners, one for each of the Company's gathering systems connected to the Company's Satanta gas plant. The case was relatively inactive for several years. In early 2000, the plaintiffs amended their pleadings and it now contains two material claims. First, the plaintiffs assert that they were improperly charged expenses (primarily field compression), which are a "cost of production", and for which the plaintiffs, as royalty owners, are not responsible. Second, the plaintiffs claim they are entitled to 100 percent of the value of the helium extracted at the Company's Satanta gas plant. If the plaintiffs were to prevail on the above two claims in their entirety, it is possible that the Company's liability (both for periods covered by the lawsuit and from the last date covered by the lawsuit to the present - because the deductions continue to be taken and the plaintiffs continue to be paid for a royalty share of the helium) could reach $65.0 million, plus prejudgment interest. However, the Company believes it has valid defenses to the plaintiffs' claims, has paid the plaintiffs properly under their respective oil and gas leases and other agreements, and intends to vigorously defend itself.

The Company does not believe the costs it has deducted are a "cost of production". The costs being deducted are post production costs incurred to transport the gas to the Company's Satanta gas plant for processing, where the valuable hydrocarbon liquids and helium are extracted from the gas. The plaintiffs benefit from such extractions and the Company believes that charging the plaintiffs with their proportionate share of such transportation and processing expenses is consistent with Kansas law and with the parties' agreements.

The Company has also vigorously defended against plaintiffs' claims to 100 percent of the value of the helium extracted, and believes that in accordance with applicable law, it has properly accounted to the plaintiffs for their fractional royalty share of the helium under the specified royalty clauses of the respective oil and gas leases.

The factual evidence in the case was presented to the 26th Judicial District Court without a jury in December 2001. Oral arguments were heard by the court in April 2002, and although the court has not yet entered a judgment or findings, it could do so at any time. The Company strongly denies the existence of any material underpayment to the plaintiffs and believes it presented strong evidence at trial to support its positions. Although the amount of any resulting liability could have a material adverse effect on the Company's results of operations for the quarterly reporting period in which such liability is recorded, the Company does not expect that any such liability will have a material adverse effect on its consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations.

Kansas ad valorem tax. The Natural Gas Policy Act of 1978 ("NGPA") allows a "severance, production or similar" tax to be included as an add-on, over and above the maximum lawful price for gas. Based on a Federal Energy Regulatory Commission ("FERC") ruling that Kansas ad valorem tax was such a tax, one of the Company's predecessor entities collected the Kansas ad valorem tax in addition to the otherwise maximum lawful price. The FERC's ruling was appealed to the United States Court of Appeals for the District of Columbia ("D.C. Circuit"), which held in June 1988 that the FERC failed to provide a reasonable basis for its findings and remanded the case to the FERC for further consideration.

On December 1, 1993, the FERC issued an order reversing its prior ruling, but limited the effect of its decision to Kansas ad valorem taxes for sales made on or after June 28, 1988. The FERC clarified the effective date of its decision by an order dated May 18, 1994. The order clarified that the effective date applies to tax bills rendered after June 28, 1988, not sales made on or after that date. Numerous parties filed appeals on the FERC's action in the D.C. Circuit. Various gas producers challenged the FERC's orders on two grounds: (1) that the Kansas ad valorem tax, properly understood, does qualify for reimbursement under the NGPA; and (2) the FERC's ruling should, in any event, have been applied prospectively. Other parties challenged the FERC's orders on the grounds that the FERC's ruling should have been applied retroactively to December 1, 1978, the date of the enactment of the NGPA and producers should have been required to pay refunds accordingly.

The D.C. Circuit issued its decision on August 2, 1996, which holds that producers must make refunds of all Kansas ad valorem tax collected with respect to production since October 4, 1983, as opposed to June 28, 1988. Petitions for rehearing were denied on November 6, 1996. Various gas producers subsequently filed a petition for writ of certiori with the United States Supreme Court seeking to limit the scope of the potential refunds to tax bills rendered on or after June 28, 1988 (the effective date originally selected by the FERC). Williams Natural Gas Company filed a cross-petition for certiori seeking to impose refund liability back to December 1, 1978. Both petitions were denied on May 12, 1997.

The Company and other producers filed petitions for adjustment with the FERC on June 24, 1997. The Company was seeking a waiver or set-off from the FERC with respect to that portion of the refund associated with (i) nonrecoupable royalties, (ii) nonrecoupable Kansas property taxes based, in part, upon the higher prices collected and (iii) interest for all periods. On September 10, 1997, FERC denied this request, and on October 10, 1997, the Company and other producers filed a request for rehearing. Pipelines were given until November 10, 1997 to file claims on refunds sought from producers and refund claims totaling approximately $30.2 million were made against the Company. Through December 31, 2003, the Company has settled $21.6 million of the original claim amounts. As of December 31, 2003 and 2002, the Company had on deposit $10.7 million and $10.6 million, respectively, including accrued interest, in an escrow account and had corresponding obligations for the remaining claim recorded in other current liabilities in the accompanying Consolidated Balance Sheets. On December 1, 2003, an administrative law judge issued a Partial Initial Decision denying the Company's request to allow any waiver or set-off from the refunds and stating that the Company must pay the FERC interest rate on the refund claims instead of the escrow interest rate. The Company has accrued an additional $1.5 million obligation for the difference between the escrow interest rate and the FERC interest rate, although the Company intends to vigorously appeal the decision. The Company believes that the accrued obligations will be sufficient to resolve the remaining claims.

Lease agreements. The Company leases offshore production facilities, equipment and office facilities under noncancellable operating leases. Rental expenses associated with these operating leases for the years ended December 31, 2003, 2002 and 2001 were approximately $15.5 million, $6.7 million and $6.6 million, respectively. Future minimum lease commitments under noncancellable operating leases at December 31, 2003 are as follows (in thousands):

2004	$ 35,515
2005	$ 43,442
2006	$ 38,227
2007	$ 27,612
2008	$ 17,338
Thereafter	$ 24,174

Drilling commitments. The Company periodically enters into contractual arrangements under which the Company is committed to expend funds to drill wells in the future. The Company also enters into agreements to secure drilling rig services which require the Company to make future minimum payments to the rig operators. The Company records drilling commitments in the periods in which well capital is expended or rig services are provided.

Transportation agreements. The Company's wholly-owned Canadian subsidiary is a party to pipeline transportation service agreements, with remaining terms of approximately 12 years, whereby it has committed to transport a specified volume of gas each year from Canada to a point in Chicago. Such gas volumes are comprised of a significant portion of the Company's Canadian net production, augmented with certain volumes purchased at market prices in Canada. The committed volumes to be transported under the pipeline transportation service agreements are approximately 78 MMcf of gas per day during 2004 and declineto approximately 75 MMcf of gas per day by the end of the commitment term. The net gas marketing gains or losses resulting from purchasing third party gas in Canada and selling it in Chicago are recorded as other income or other expense in the accompanying Consolidated Statements of Operations. Associated with these agreements, the Company recognized $922 thousand, $2.6 million and $9.9 million of gas marketing losses in other expenses during the years ended December 31, 2003, 2002 and 2001, respectively.

NOTE J. Derivative Financial Instruments

Hedge Derivatives

The Company utilizes derivative instruments to manage commodity price, interest rate and foreign exchange rate risks.

Fair value hedges. The Company monitors the debt capital markets and interest rate trends to identify opportunities to enter into and terminate interest rate swap contracts with the objective of minimizing costs of capital. During the three-year period ending December 31, 2003, the Company, from time to time, entered into interest rate swap contracts to hedge a portion of the fair value of its senior notes. The terms of the interest rate swap contracts were for notional amounts that matched the scheduled maturity of the bonds, required the counterparties topay the Company a fixed annual interest rate equal to the stated bond coupon rates on the notional amounts and required the Company to pay the counterparties variable annual interest rates on the notional amounts equal to the periodic six-month LIBOR plus a weighted average margin.

During the years ended December 31, 2003, 2002 and 2001, the Company recognized interest savings associated with its interest rate swap contracts of $29.3 million, $25.3 million and $7.3 million, respectively. During the years ended December 31, 2003, 2002 and 2001, the Company terminated interest rate swap contracts for cash proceeds, including accrued interest, of $21.5 million, $36.3 million and $23.3 million, respectively. The proceeds attributable to the fair value of the remaining terms of the terminated contracts amounted to $18.3 million, $32.0 million and $21.2 million and are included in "Proceeds from disposition of assets" in the accompanying Consolidated Statements of Cash Flows during the years ended December 31, 2003, 2002 and 2001, respectively. As of December 31, 2003 and 2002, the Company was not a party to any fair value hedges.

As of December 31, 2003, the carrying value of the Company's long-term debt in the accompanying Consolidated Balance Sheets included $27.4 million of incremental carrying value attributable to the unamortized net deferred hedge gains realized from terminated fair value hedge interest rate swap contracts. The amortization of these net deferred hedge gains reduced the Company's reported interest expense by $26.1 million, $14.1 million and $2.8 million during the years ended December 31, 2003, 2002 and 2001, respectively.

The following table sets forth the scheduled amortization of net deferred hedge gains and losses on terminated fair value hedges as of December 31, 2003 that will be recognized as increases in the case of losses, or decreases in the case of gains, to the Company's future interest expense:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Yearly Total
			(in thousands)		
2004 net hedge gain amortization . . .	$ 7,308	$ 6,116	$ 5,489	$ 4,555	$ 23,468
2005 net hedge gain amortization . . .	$ 4,264	$ 2,816	$ 2,313	$ 1,575	10,968
Remaining net losses to be amortized through 2010					(7,062)
					$ 27,374

The terms of the fair value hedges described above perfectly matched the terms of the underlying senior notes. The Company did not exclude any component of the derivatives' gains or losses from the measurement of hedge effectiveness.

Cash flow hedges. The Company utilizes commodity swap and collar contracts to (i) reduce the effect of price volatility on the commodities the Company produces and sells, (ii) support the Company's annual capital budgeting and expenditure plans and (iii) reduce commodity price risk associated with certain capital projects. The Company has also utilized interest rate swap contracts to reduce the effect of interest rate volatility on the Company's variable rate line of credit indebtedness and forward currency exchange contracts to reduce the effect of U.S. dollar to Canadian dollar exchange rate volatility.

Oil prices. All material sales contracts governing the Company's oil production have been tied directly or indirectly to NYMEX prices. The following table sets forth the Company's outstanding oil hedge contracts and the weighted average NYMEX prices for those contracts as of December 31, 2003:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Yearly Outstanding Average
Daily oil production:					
2004 - Swap Contracts					
Volume (Bbl)	24,000	24,000	14,000	14,000	18,973
Price per Bbl	$ 26.59	$ 26.51	$ 24.65	$ 24.65	$ 25.84
2005 - Swap Contracts					
Volume (Bbl)	17,000	17,000	17,000	17,000	17,000
Price per Bbl	$ 24.93	$ 24.93	$ 24.93	$ 24.93	$ 24.93
2006 - Swap Contracts					
Volume (Bbl)	5,000	5,000	5,000	5,000	5,000
Price per Bbl	$ 26.19	$ 26.19	$ 26.19	$ 26.19	$ 26.19
2007 - Swap Contracts					
Volume (Bbl)	1,000	1,000	1,000	1,000	1,000
Price per Bbl	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00
2008 - Swap Contracts					
Volume (Bbl)	5,000	5,000	5,000	5,000	5,000
Price per Bbl	$ 26.09	$ 26.09	$ 26.09	$ 26.09	$ 26.09

The Company reports average oil prices per Bbl including the effects of oil quality adjustments and the net effect of oil hedges. The following table sets forth the Company's oil prices, both reported (including hedge results) and realized (excluding hedge results), and the net effect of settlements of oil price hedges on oil revenue for the years ended December 31, 2003, 2002 and 2001:

	Year Ended December 31,		
	2003	2002	2001
Average price reported per Bbl	$ 25.59	$ 22.89	$ 24.12
Average price realized per Bbl	$ 28.80	$ 22.95	$ 23.88
Addition (reduction) to oil revenue (in millions)	$ (41.3)	$ (.8)	$ 3.0

Natural gas liquids prices. During the years ended December 31, 2003, 2002 and 2001, the Company did not enter into any NGL hedge contracts. There were no outstanding NGL hedge contracts at December 31, 2003.

Gas prices. The Company employs a policy of hedging a portion of its gas production based on the index price upon which the gas is actually sold, or based on NYMEX prices if NYMEX prices are highly correlated with the index price, in order to mitigate the basis risk between NYMEX prices and actual index prices. The following table sets forth the Company's outstanding gas hedge contracts and the weighted average index prices for those contracts as of December 31, 2003:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Yearly Outstanding Average
Daily gas production:					
2004 - Swap Contracts					
Volume (Mcf)	295,934	280,000	280,000	280,000	283,962
Index price per MMBtu	$ 4.27	$ 4.11	$ 4.11	$ 4.11	$ 4.16
2005 - Swap Contracts					
Volume (Mcf)	60,000	60,000	60,000	60,000	60,000
Index price per MMBtu	$ 4.24	$ 4.24	$ 4.24	$ 4.24	$ 4.24
2006 - Swap Contracts					
Volume (Mcf)	70,000	70,000	70,000	70,000	70,000
Index price per MMBtu	$ 4.16	$ 4.16	$ 4.16	$ 4.16	$ 4.16
2007 - Swap Contracts					
Volume (Mcf)	20,000	20,000	20,000	20,000	20,000
Index price per MMBtu	$ 3.51	$ 3.51	$ 3.51	$ 3.51	$ 3.51

The Company reports average gas prices per Mcf including the effects of Btu content, gas processing and shrinkage adjustments and the net effect of gas hedges. The following table sets forth theCompany's gas prices, both reported (including hedge results) and realized (excluding hedge results), and the net effect of settlements of gas price hedges on gas revenue:

	Year Ended December 31,		
	2003	2002	2001
Average price reported per Mcf	$ 3.81	$ 2.49	$ 3.23
Average price realized per Mcf	$ 4.17	$ 2.38	$ 3.20
Addition (reduction) to gas revenue (in millions)	$ (76.1)	$ 13.6	$ 3.0

Hedge ineffectiveness and excluded items. During the years ended December 31, 2003, 2002 and 2001, the Company recognized other expense of $2.8 million, $1.7 million and $9.1 million, respectively, related to the ineffective portions of its cash flow hedging instruments. Additionally, based on SFAS 133 interpretive guidance that was in effect prior to April 2001, the Company excluded from the measurement of hedge effectiveness changes in the time and volatility value components of collar contracts designated as cash flow hedges. Associated therewith, the Company recorded other expense of $2.4 million during the three month period ended March 31, 2001. In April 2001, the Company discontinued the exclusion of time value and volatility from the measurement of hedge effectiveness.

Accumulated other comprehensive income (loss) - net deferred hedge gains (losses), net of tax. As of December 31, 2003 and 2002, AOCI - net deferred hedge gains (losses), net of tax represented net deferred losses of $104.1 million and net deferred gains of $9.6 million, respectively. The AOCI - net deferred hedge gains (losses), net of tax balance as of December 31, 2003 was comprised of $200.6 million of net deferred hedge losses on the effective portions of open commodity cash flow hedges, $45.1 million of net deferred gains on terminated cash flow hedges and $51.4 million of associated net deferred tax benefits. The AOCI - net deferred hedge gains (losses), net of tax balance as of December 31, 2002 was comprised of $108.1 million of net deferred hedge losses on the effective portions of open commodity cash flow hedges, $117.4 million of net deferred gains on terminated cash flow hedges and $.3 million of associated net deferred tax benefits. The decrease in AOCI - net deferred hedge gains (losses), net of tax during the year ended December 31, 2003 was primarily attributable to increases in future commodity prices relative to the commodity prices stipulated in the hedge agreements and the reclassification of net deferred hedge gains to net income as derivatives matured by their terms, partially offset by a $51.1 million increase in associated deferred income tax benefits (see Note P for information regarding the Company's United States deferred tax valuation allowance). The net deferred hedge gains and losses associated with open cash flow hedges remain subject to market price fluctuations until the positions are either settled under the terms of the hedge contracts or terminated prior to settlement. The net deferred gains and losses on terminated cash flow hedges are fixed.

During the twelve month period ending December 31, 2004, the Company expects to reclassify $151.9 million of net deferred losses associated with open cash flow hedges and $43.9 million of net deferred gains on terminated cash flow hedges from AOCI - net deferred hedge gains (losses), net of tax to oil and gas revenue. The Company also expects to reclassify approximately $39.6 million of deferred income tax benefits during the twelve months ending December 31, 2004 from AOCI - net deferred hedge gains (losses), net of tax to income tax benefit (provision).

The following table sets forth the scheduled reclassifications of net deferred hedge gains on terminated cash flow hedges as of December 31, 2003, that will be recognized in the Company's future oil and gas revenues:

	First Quarter	Second Quarter	Third Quarter (in thousands)	Fourth Quarter	Yearly Total
2004 net deferred hedge gains	$ 10,978	$ 10,932	$ 11,001	$ 10,954	$ 43,865
2005 net deferred hedge gains	$ 307	$ 310	$ 315	$ 317	1,249
					$ 45,114

Non-hedge Derivatives

Btu swap contracts. The Company is a party to Btu swap contracts that mature at the end of 2004. The Btu swap contracts do not qualify for hedge accounting treatment. The Company recorded mark-to-market adjustments to decrease the carrying value of the Btu swap liability by $.7 million during the year ended December 31, 2001. During the year ended December 31, 2001, the Company entered into offsetting Btu swap contracts that fixed the Company's remaining obligations associated with the Btu swap contracts. The remaining undiscounted future settlement obligations of the Company under the Btu swap contracts are $7.2 million for 2004.

NOTE K. Major Customers and Derivative Counterparties

Sales to major customers. The Company's share of oil and gas production is sold to various purchasers who must be prequalified under the Company's credit risk policies and procedures. The Company is of the opinion that the loss of any one purchaser would not have an adverse effect on the ability of the Company to sell its oil and gas production.

The following customers individually accounted for 10 percent or more of the consolidated oil, NGL and gas revenues of the Company during one or more of the years ended December 31, 2003, 2002 and 2001:

	Percentage of Consolidated Oil, NGL and Gas Revenues		
	2003	2002	2001
Williams Energy Services	16	7	11
Anadarko Petroleum Corporation	4	7	10

At December 31, 2003, the amount receivable from Anadarko Petroleum Corporation was $1.5 million which is included in the caption "Accounts receivable - trade, net" in the accompanying Consolidated Balance Sheet. The Company had no accounts receivable - trade, net from Williams Energy Services at December 31, 2003.

Derivative counterparties. The Company uses credit and other financial criteria to evaluate the credit standing of, and to select, counterparties to its derivative instruments. Although the Company does not obtain collateral or otherwise secure the fair value of its derivative instruments, associated credit risk is mitigated by the Company's credit risk policies and procedures. As of December 31, 2003 and 2002, the Company had $7.6 million of derivative assets for which Enron North America Corp was the Company's counterparty. Associated therewith, the Company recognized bad debt expense of $.4 million and $6.0 million as components of other expense in the accompanying Consolidated Statements of Operations during the years ended December 31, 2002 and 2001, respectively.

NOTE L. Asset Retirement Obligations

As referred to in Note B, the Company adopted the provisions of SFAS 143 on January 1, 2003. The Company's asset retirement obligations primarily relate to the future plugging and abandonment of proved properties and related facilities. The Company does not provide for a market risk premium associated with asset retirement obligations because a reliable estimate cannot be determined. The Company has no assets that are legally restricted for purposes of settling asset retirement obligations. The following table summarizes the Company's asset retirement obligation transactions recorded in accordance with the provisions of SFAS 143 during the year ended December 31, 2003 and in accordance with the provisions of SFAS 19 during the years ended December 31, 2002 and 2001:

	Year Ended December 31,		
	2003	2002 (in thousands)	2001
Beginning asset retirement obligations	$ 34,692	$ 39,461	$ 41,983
Cumulative effect adjustment	23,393	-	-
New wells placed on production and changes in estimates	46,664	293	-
Acquisition liabilities assumed	1,791	-	981
Liabilities settled	(8,069)	(6,832)	(3,287)
Accretion expense	5,040	2,562	2,590
Currency translation	1,525	(792)	(2,806)
Ending asset retirement obligations	$ 105,036	$ 34,692	$ 39,461

NOTE M. Interest and Other Income

The following table provides the components of the Company's interest and other income during the years ended December 31, 2003, 2002 and 2001:

	Year Ended December 31,		
	2003	2002	2001
		(in thousands)	
Kansas ad valorem escrow adjustments (see Note I)	$ -	$ 3,500	$ 1,100
Retirement obligation revaluations	4,410	-	-
Excise tax income	2,369	2,398	4,126
Production payment income	-	-	5,552
Interest income	981	642	2,128
Seismic data sales	424	87	1,841
Foreign exchange gains	657	142	223
Other income	3,451	4,453	6,808
Total interest and other income	$ 12,292	$ 11,222	$ 21,778

NOTE N. Asset Divestitures

During the years ended December 31, 2003, 2002 and 2001, the Company completed asset divestitures for net proceeds of $35.7 million, $118.9 million and $113.5 million, respectively. Associated therewith, the Company recorded gains on disposition of assets of $1.3 million, $4.4 million and $7.7 million during the years ended December 31, 2003, 2002 and 2001, respectively.

Hedge derivative divestitures. During the years ended December 31, 2003, 2002 and 2001, the Company terminated, prior to their scheduled maturity, hedge derivatives for cash sales proceeds of $18.3 million, $91.3 million and $85.4 million, respectively. Net gains from these divestitures were deferred and are being amortized over the original contract lives of the terminated derivatives as reductions to interest expense or increases to oil and gas revenues. See Note J for more information regarding deferred gains on terminated hedge derivatives.

Available for sale securities divestitures. During the year ended December 31, 2001, the Company sold its remaining 613,250 shares of common stock of an unaffiliated entity for $12.7 million of cash proceeds and recognized an associated gain on disposition of assets of $8.1 million.

Other United States divestitures. During the year ended December 31, 2003, the Company received $15.2 million of cash proceeds from the sale of unproved property interests and $.9 million of cash proceeds from the sale of other U.S. corporate assets. Associated with these divestitures, the Company recorded $1.5 million of net gains. During the year ended December 31, 2002, the Company received $20.9 million of proceeds from the cash settlement of a gas balancing receivable, $4.7 million from the sale of certain gas properties located in Oklahoma and $1.8 million from the sale of other corporate assets. Associated with these divestitures, the Company recorded net gains of $4.2 million.

Other international divestitures. During the year ended December 31, 2001, the Company received $12.0 million of proceeds from the sale of certain oil properties in Canada and $.4 million of proceeds from the sale of other international assets. Associated with these transactions, the Company recognized a net loss of $.8 million.

NOTE O. Other Expense

The following table provides the components of the Company's other expense during the years ended December 31, 2003, 2002 and 2001:

	Years Ended December 31,		
	2003	2002	2001
		(in thousands)	
Derivative ineffectiveness and mark-to-market provisions (see Note J)	$ 2,831	$ 1,664	$ 11,458
Gas marketing losses (see Note I)	922	2,556	9,850
Foreign currency remeasurement and exchange losses (a)	2,672	7,623	8,474
Bad debt expense (see Note K)	354	129	6,152
Loss on early extinguishment of debt (see Note E)	1,457	22,346	3,753
Kansas ad valorem escrow adjustments (see Note I)	1,776	-	-
Argentine personal asset tax	1,996	-	-
Other charges	9,312	5,284	3,654
Total other expense	$ 21,320	$ 39,602	$ 43,341

(a) The Company's operations in Argentina, Canada and Africa periodically recognize monetary assets and liabilities in currencies other than their functional currencies (see Note B for information regarding the functional currencies of subsidiary entities). Associated therewith, the Company realizes foreign currency remeasurement and transaction gains and losses.

NOTE P. Income Taxes

The Company accounts for income taxes in accordance with the provisions of Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes" ("SFAS 109"). The Company and its eligible subsidiaries file a consolidated United States federal income tax return. Certain subsidiaries are not eligible to be included in the consolidated United States federal income tax return and separate provisions for income taxes have been determined for these entities or groups of entities. The tax returns and the amount of taxable income or loss are subject to examination by United States federal, state and foreign taxing authorities. Current and estimated tax payments of $5.3 million, $2.3 million and $11.7 million were made during the years ended December 31, 2003, 2002 and 2001, respectively.

From 1998 until 2003, the Company maintained a valuation allowance against a portion of its deferred tax asset position in the United States. SFAS 109 requires that the Company continually assess both positive and negative evidence to determine whether it is more likely than not that deferred tax assets can be realized prior to their expiration. In the third quarter of 2003 and as of December 31, 2003, the Company has concluded that it is more likely than not that it will realize its gross deferred tax asset position in the United States after giving consideration to the following specific facts:

- Over the past several years, the Company has been steadily improving its portfolio of assets, including significant proved reserve discoveries and follow-up development projects that have recently started to produce. Specifically, Pioneer completed development activities and began production operations on its Canyon Express gas project in September 2002 and on its Company-operated Falcon field gas project in March 2003. The production performance to-date and the reservoir data that has been accumulated on these projects provide assurance that these projects will recover the reserves as predicted.

- During 2003, the Company announced additional Falcon area discoveries in the Harrier, Tomahawk and Raptor fields and during January 2004, the Harrier development project was completed and began production operations. The Company expects first production from the Tomahawk and Raptor fields in mid-2004. The Company also expects to complete its other significant Gulf of Mexico development project, Devils Tower, in mid-2004.

- Commodity market supply and demand fundamentals continued to stabilize during the third and fourth quarters of 2003 as evidenced by quoted futures prices that suggest that North American gas prices will remain relatively flat over the next five years and that worldwide oil prices may decline modestly over that time span compared to relatively high current levels for each commodity.

- The Company's future revenues are further protected against price declines through its significant hedging program. The Company has hedged portions of its oil price risk through 2008 and portions of its gas price risk through 2007. See Note J for information regarding the Company's hedge positions.

- The Company generated record pretax income for the third quarter of 2003 and net income in each of the years ended December 31, 2003, 2002, 2001 and 2000. The Company also generated taxable income during 2003, including the deduction of 100 percent of its intangible drilling costs. The Company believes that these trends will continue for the foreseeable future.

- The Company performed various economic evaluations in the third quarter of 2003 to determine if the Company would be able to realize all of its deferred tax assets, including its net operating loss carryforwards, prior to any expiration. These evaluations were based on the Company's reserve projections of existing producing properties and recent discoveries being developed. These evaluations employed varying price assumptions, some of which included a significant reduction in commodity prices, and factored in limitations on the use of the Company's net operating loss carryforwards. The evaluations did not include assumptions of increases in proved reserves through future exploration or acquisitions. The evaluations indicated that the deferred tax assets are realizable in the future.

Accordingly, during the third quarter of 2003, the Company reversed its remaining valuation allowance in the United States, resulting in the recognition of a deferred tax benefit of $104.7 million. For 2003 in total, the Company reversed $197.7 million of United States valuation allowances resulting in a net deferred tax benefit for the year. Further, the third quarter reversal of the allowance increased stockholders' equity by $32.6 million as the Company recognized the tax effects of previous stock option exercises and deferred hedging gains and losses in other comprehensive income.

Pioneer will continue to monitor Company-specific, oil and gas industry and worldwide economic factors and will reassess the likelihood that the Company's net operating loss carryforwards and other deferred tax attributes will be utilized prior to their expiration. There can be no assurances that facts and circumstances will not materially change and require the Company to reestablish a United States deferred tax asset valuation allowance in a future period. As of December 31, 2003, the Company does not believe there is sufficient positive evidence to reverse its valuation allowances related to foreign tax jurisdictions.

During the years ended December 31, 2003, 2002 and 2001, the Company's income tax provision (benefit) and amounts separately allocated were attributable to the following items:

	Year Ended December 31,		
	2003	2002	2001
		(in thousands)	
Income before cumulative effect of change in accounting principle	$ (64,403)	$ 5,063	$ 4,016
Cumulative effect of change in accounting principle	1,312	-	-
Changes in stockholders' equity:			
Net deferred hedge gains and losses	(51,064)	(2,561)	2,293
Tax benefits related to stock-based compensation	(14,666)	-	-
Translation adjustment	(324)	(20)	(121)
	$ (129,145)	$ 2,482	$ 6,188

Income tax provision (benefit) attributable to income before cumulative effect of change in accounting principle consists of the following:

	Year Ended December 31,		
	2003	2002	2001
		(in thousands)	
Current:			
U.S. federal	$ 100	$ -	$ -
U.S. state and local	-	209	1,080
Foreign	11,085	2,066	10,585
	11,185	2,275	11,665
Deferred:			
U.S. federal	(69,020)	-	-
U.S. state and local	(7,291)	-	-
Foreign	723	2,788	(7,649)
	(75,588)	2,788	(7,649)
	$ (64,403)	$ 5,063	$ 4,016

Income before income taxes and cumulative effect of change inaccounting principle consists of the following:

	Year Ended December 31,		
	2003	2002	2001
		(in thousands)	
Income before income taxes and cumulative effect of change in accounting principle:			
U.S. federal	$ 335,170	$ 36,475	$ 136,292
Foreign	(4,394)	(4,699)	(32,280)
	$ 330,776	$ 31,776	$ 104,012

Reconciliations of the United States federal statutory tax rate to the Company's effective tax rate for income before cumulative effect of change in accounting principle are as follows:

	2003	2002	2001
U.S. federal statutory tax rate	35.0	35.0	35.0
U.S. valuation allowance reversal	(59.8)	(44.1)	(38.5)
Foreign valuation allowances (a)	13.1	28.2	11.2
Rate differential on foreign operations	(.9)	(.5)	(3.3)
Argentine inflation adjustment (a)	(12.4)	-	-
Other	5.5	(2.7)	(.6)
Consolidated effective tax rate	(19.5)	15.9	3.8

(a) The Company has applied an inflation adjustment to its 2002 Argentine income tax return based on developing case law. The Company believes that it is more likely than not that the adjustment will be denied by the Argentine taxing authorities and has provided a $40.8 million valuation allowance against this tax benefit.

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities are as follows:

	December 31,	
	2003	2002
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 300,296	$ 299,495
Alternative minimum tax credit carryforwards	1,457	1,565
Net deferred hedge gains and losses	56,842	41,544
Asset retirement obligations	29,040	12,402
Other	92,561	89,948
Total deferred tax assets	480,196	444,954
Valuation allowances	(94,910)	(277,217)
Net deferred tax assets	385,286	167,737
Deferred tax liabilities:		
Oil and gas properties, principally due to differences in basis, depletion and the deduction of intangible drilling costs for tax purposes	161,532	80,364
Other	3,017	5,393
Total deferred tax liabilities	164,549	85,757
Net deferred tax asset	$ 220,737	$ 81,980

At December 31, 2003, the Company had NOLs for United States, Argentine, Canadian, Gabonese, South African and Tunisian income tax purposes of $746.6 million, $3.9 million, $26.3 million, $17.0 million, $47.7 million and $9.0 million, respectively, which are available to offset future regular taxable income in each respective tax jurisdiction, if any. Additionally, at December 31, 2003, the Company has alternative minimum tax net operating loss carryforwards ("AMT NOLs") in the United States of $653.0 million, which are available to reduce future alternative minimum taxable income, if any. These carryforwards expire as follows:

Expiration Date	U.S. NOL	U.S. AMT NOL	Argentina NOL	Canada NOL	Gabon NOL	South Africa NOL	Tunisia NOL
				(in thousands)			
December 31, 2005	$ -	$ -	$ -	$ 19,288	$ -	$ -	$ -
December 31, 2006	33,011	27,133	-	7,048	-	-	-
December 31, 2007	181,049	156,447	3,928	-	-	-	-
December 31, 2008	102,271	106,558	-	-	-	-	-
December 31, 2009	37,974	21,551	-	-	-	-	-
December 31, 2010	25,144	15,253	-	-	-	-	-
December 31, 2012	68,334	58,723	-	-	-	-	-
December 31, 2018	127,970	98,604	-	-	-	-	-
December 31, 2019	142,518	141,355	-	-	-	-	-
December 31, 2020	14,387	13,449	-	-	-	-	-
December 31, 2021	13,895	13,895	-	-	-	-	-
Indefinite	-	-	-	-	17,036	47,704	8,980
	$ 746,553	$ 652,968	$ 3,928	$ 26,336	$ 17,036	$ 47,704	$ 8,980

The Company believes $140.0 million of the U.S. NOLs and AMT NOLs are subject to Section 382 of the Internal Revenue Code and are limited in each taxable year to approximately $20.0 million.

NOTE Q. Income Per Share Before Cumulative Effect of Change in Accounting Principle

Basic income per share before cumulative effect of change in accounting principle is computed by dividing income before cumulative effect of change in accounting principle by the weighted average number of common shares outstanding for the period. The computation of diluted income per share before cumulative effect of change in accounting principle reflects the potential dilution that could occur if securities or other contracts to issue common stock that are dilutive to income before cumulative effect of change in accounting principle were exercised or converted into common stock or resulted in the issuance of common stock that would then share in the earnings of the Company.

The following table is a reconciliation of the basic and diluted weighted average common shares outstanding for the years ended December 31, 2003, 2002 and 2001:

	Year Ended December 31,		
	2003	2002	2001
		(in thousands)	
Weighted average common shares outstanding:			
Basic	117,185	112,542	98,529
Dilutive common stock options (a)	1,112	1,725	1,185
Restricted stock awards	216	21	-
Diluted	118,513	114,288	99,714

(a) Common stock options to purchase 976,506 shares, 1,925,743 shares and 3,595,880 shares of common stock were outstanding but not included in the computations of diluted income per share before cumulative effect of change in accounting principle for the years ended December 31, 2003, 2002 and 2001, respectively, because the exercise prices of the options were greater than the average market price of the common shares and would be anti-dilutive to the computations.

NOTE R. Geographic Operating Segment Information

The Company has operations in only one industry segment, that being the oil and gas exploration and production industry; however, the Company is organizationally structured along geographic operating segments, or regions. The Company has reportable operations in the United States, Argentina and Canada. Other foreign is primarily comprised of operations in Gabon, South Africa and Tunisia.

The following table provides the geographic operating segment data required by Statement of Financial Accounting Standards No. 131, "Disclosure about Segments of an Enterprise and Related Information", as well as results of operations of oil and gas producing activities required by Statement of Financial Accounting Standards No. 69, "Disclosures about Oil and Gas Producing Activities" as of and for the years ended December 31, 2003, 2002 and 2001. Geographic operating segment income tax benefits (provisions) have been determined based on statutory rates existing in the various tax jurisdictions where the Company has oil and gas producing activities. The "Headquarters and Other" table column includes revenues, expenses, additions to properties, plant and equipment and assets that are not routinely included in the earnings measures or attributes internally reported to management on a geographic operating segment basis.

	United States	Argentina	Canada	Other Foreign	Headquarters and Other	Consolidated Total
			(in thousands)			
Year Ended December 31, 2003:						
Oil and gas revenues	$ 1,097,365	$ 111,315	$ 68,624	$ 21,343	$ -	$ 1,298,647
Interest and other	-	-	-	-	12,292	12,292
Gain (loss) on disposition of assets, net	1,458	-	1	-	(203)	1,256
	1,098,823	111,315	68,625	21,343	12,089	1,312,195
Oil and gas production	237,484	26,110	13,045	2,887	-	279,526
Depletion, depreciation and amortization	298,005	46,518	28,991	7,729	9,597	390,840
Exploration and abandonments	72,732	18,076	17,691	24,261	-	132,760
General and administrative	-	-	-	-	60,545	60,545
Accretion of discount on asset retirement obligations	-	-	-	-	5,040	5,040
Interest	-	-	-	-	91,388	91,388
Other	-	-	-	-	21,320	21,320
	608,221	90,704	59,727	34,877	187,890	981,419
Income (loss) before income taxes and cumulative effect of change in accounting principle	490,602	20,611	8,898	(13,534)	(175,801)	330,776
Income tax benefit (provision)	(179,070)	(7,214)	(3,426)	4,738	249,375	64,403
Income (loss) before cumulative effect of change in accounting principle	$ 311,532	$ 13,397	$ 5,472	$ (8,796)	$ 73,574	$ 395,179
Cost incurred for long-lived assets	$ 563,013	$ 52,138	$ 53,030	$ 54,819	$ -	$ 723,000
Segment assets (as of December 31, 2003)	$ 2,631,240	$ 689,781	$ 224,925	$ 159,747	$ 245,879	$ 3,951,572
Year Ended December 31, 2002:						
Oil and gas revenues	$ 573,289	$ 77,615	$ 50,876	$ -	$ -	$ 701,780
Interest and other	-	-	-	-	11,222	11,222
Gain (loss) on disposition of assets, net	3,248	(3)	995	-	192	4,432
	576,537	77,612	51,871	-	11,414	717,434
Oil and gas production	174,929	13,870	10,771	-	-	199,570
Depletion, depreciation and amortization	140,107	39,659	27,857	-	8,752	216,375
Exploration and abandonments	62,955	10,306	5,841	6,792	-	85,894
General and administrative	-	-	-	-	48,402	48,402
Interest	-	-	-	-	95,815	95,815
Other	-	-	-	-	39,602	39,602
	377,991	63,835	44,469	6,792	192,571	685,658
Income (loss) before income taxes	198,546	13,777	7,402	(6,792)	(181,157)	31,776
Income tax benefit (provision)	(69,491)	(4,822)	(3,118)	2,377	69,991	(5,063)
Net income (loss)	$ 129,055	$ 8,955	$ 4,284	$ (4,415)	$ (111,166)	$ 26,713
Cost incurred for long-lived assets	$ 533,560	$ 35,121	$ 33,506	$ 70,268	$ -	$ 672,455
Segment assets (as of December 31, 2002)	$ 2,375,505	$ 680,063	$ 176,110	$ 118,070	$ 105,368	$ 3,455,116
Year Ended December 31, 2001:						
Oil and gas revenues	$ 649,635	$ 130,241	$ 67,146	$ -	$ -	$ 847,022
Interest and other	-	-	-	-	21,778	21,778
Gain (loss) on disposition of assets, net	224	-	(1,339)	-	8,796	7,681
	649,859	130,241	65,807	-	30,574	876,481
Oil and gas production	170,578	26,614	12,472	-	-	209,664
Depletion, depreciation and amortization	128,477	51,391	28,868	-	13,896	222,632
Exploration and abandonments	70,049	23,857	9,882	24,118	-	127,906
General and administrative	-	-	-	-	36,968	36,968
Interest	-	-	-	-	131,958	131,958
Other	-	-	-	-	43,341	43,341
	369,104	101,862	51,222	24,118	226,163	772,469
Income (loss) before income taxes	280,755	28,379	14,585	(24,118)	(195,589)	104,012
Income tax benefit (provision)	(98,264)	(9,933)	(6,216)	8,441	101,956	(4,016)
Net income (loss)	$ 182,491	$ 18,446	$ 8,369	$ (15,677)	$ (93,633)	$ 99,996
Cost incurred for long-lived assets	$ 454,229	$ 98,311	$ 36,048	$ 57,972	$ -	$ 646,560
Segment assets (as of December 31, 2001)	$ 2,212,540	$ 710,702	$ 187,841	$ 53,314	$ 106,656	$ 3,271,053

NOTE S. Pioneer USA

Pioneer USA is a wholly-owned subsidiary of the Company that has fully and unconditionally guaranteed certain debt securities of the Company (see Note E above). In accordance with practices accepted by the SEC, the Company has prepared Consolidating Condensed Financial Statements in order to quantify the assets and results of operations of Pioneer USA as a subsidiary guarantor. The following Consolidating Condensed Balance Sheets as of December 31, 2003 and 2002, and Consolidating Statements of Operations and Comprehensive Income (Loss) and Consolidating Condensed Statements of Cash Flows for the years ended December 31, 2003, 2002 and 2001 present financial information for Pioneer Natural Resources Company as the Parent on a stand-alone basis (carrying any investments in subsidiaries under the equity method), financial information for Pioneer USA on a stand-alone basis (carrying any investment in non-guarantor subsidiaries under the equity method), financial information for the non-guarantor subsidiaries of the Company on a consolidated basis, the consolidation and elimination entries necessary to arrive at the information for the Company on a consolidated basis, and the financial information for the Company on a consolidated basis. Pioneer USA is not restricted from making distributions to the Company.

CONSOLIDATING CONDENSED BALANCE SHEET
As of December 31, 2003
(in thousands)

	Parent	Pioneer USA	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
ASSETS					
Current assets:					
Cash and cash equivalents	$ 369	$ 4,225	$ 14,705	$ -	$ 19,299
Other current assets, net	1,654,575	(1,354,256)	(114,503)	-	185,816
Total current assets	1,654,944	(1,350,031)	(99,798)	-	205,115
Property, plant and equipment, at cost:					
Oil and gas properties, using the successful efforts method of accounting:					
Proved properties	-	3,508,365	1,475,193	-	4,983,558
Unproved properties	-	25,460	154,365	-	179,825
Accumulated depletion, depreciation and amortization	-	(1,208,700)	(467,436)	-	(1,676,136)
Total property, plant and equipment	-	2,325,125	1,162,122	-	3,487,247
Deferred income taxes	190,492	-	1,852	-	192,344
Other property and equipment, net	-	23,890	4,190	-	28,080
Other assets, net	14,836	17,076	6,874	-	38,786
Investment in subsidiaries	1,604,534	167,515	-	(1,772,049)	-
	$ 3,464,806	$ 1,183,575	$1,075,240	$ (1,772,049)	$ 3,951,572
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$ 29,978	$ 347,720	$ 52,054	$ -	$ 429,752
Long-term debt	1,555,461	-	-	-	1,555,461
Other liabilities	-	226,055	(31,589)	-	194,466
Deferred income taxes	-	-	12,121	-	12,121
Stockholders' equity	1,879,367	609,800	1,042,654	(1,772,049)	1,759,772
Commitments and contingencies					
	$ 3,464,806	$ 1,183,575	$1,075,240	$ (1,772,049)	$ 3,951,572

CONSOLIDATING CONDENSED BALANCE SHEET
As of December 31, 2002
(in thousands)

	Parent	Pioneer USA	Non-Guarantor Subsidiaries	Eliminations	Consolidated Total
ASSETS					
Current assets:					
Cash and cash equivalents	$ 6	$ 1,783	$ 6,701	$ -	$ 8,490
Other current assets, net	1,727,828	(1,480,657)	(108,568)	-	138,603
Total current assets	1,727,834	(1,478,874)	(101,867)	-	147,093
Property, plant and equipment, at cost:					
Oil and gas properties, using the successful efforts method of accounting:					
Proved properties	-	3,024,845	1,228,052	-	4,252,897
Unproved properties	-	43,969	175,104	-	219,073
Accumulated depletion, depreciation and amortization	-	(947,091)	(356,450)	-	(1,303,541)
Total property, plant and equipment	-	2,121,723	1,046,706	-	3,168,429
Deferred income taxes	75,311	-	1,529	-	76,840
Other property and equipment, net	-	19,000	3,784	-	22,784
Other assets, net	16,067	14,231	9,672	-	39,970
Investment in subsidiaries	1,247,042	136,159	-	(1,383,201)	-
	$ 3,066,254	$ 812,239	$ 959,824	$ (1,383,201)	$ 3,455,116
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$ 30,785	$ 216,065	$ 27,742	$ -	$ 274,592
Long-term debt	1,668,536	-	-	-	1,668,536
Other liabilities	-	147,970	(19,639)	-	128,331
Deferred income taxes	-	-	8,760	-	8,760
Stockholders' equity	1,366,933	448,204	942,961	(1,383,201)	1,374,897
Commitments and contingencies					
	$ 3,066,254	$ 812,239	$ 959,824	$ (1,383,201)	$ 3,455,116

PIONEER NATURAL RESOURCES COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2003, 2002 and 2001

CONSOLIDATING CONDENSED STATEMENT OF OPERATIONS
AND COMPREHENSIVE INCOME (LOSS)
For the Year Ended December 31, 2003
(in thousands)

	Parent	Pioneer USA	Non-Guarantor Subsidiaries	Consolidated Income Tax Provision	Eliminations	Consolidated Total
Revenues and other income:						
Oil and gas	$ -	$1,008,668	$ 289,979	$ -	$ -	$1,298,647
Interest and other	-	7,303	4,989	-	-	12,292
Gain (loss) on disposition of assets, net	-	1,403	(147)	-	-	1,256
	-	1,017,374	294,821	-	-	1,312,195
Costs and expenses:						
Oil and gas production	-	215,886	63,640	-	-	279,526
Depletion, depreciation and amortization	-	293,665	97,175	-	-	390,840
Exploration and abandonments	-	71,391	61,369	-	-	132,760
General and administrative	971	47,763	11,811	-	-	60,545
Accretion of discount on asset retirement obligations	-	3,804	1,236	-	-	5,040
Interest	23,964	66,012	1,412	-	-	91,388
Equity (income) loss from subsidiary	(362,094)	17,024	-	-	345,070	-
Other	1,465	7,387	12,468	-	-	21,320
	(335,694)	722,932	249,111	-	345,070	981,419
Income before income taxes and cumulative effect of change in accounting principle	335,694	294,442	45,710	-	(345,070)	330,776
Income tax benefit (provision)	-	-	(10,495)	74,898	-	64,403
Income before cumulative effect of change in accounting principle	335,694	294,442	35,215	74,898	(345,070)	395,179
Cumulative effect of change in accounting principle, net of tax	-	11,859	3,554	-	-	15,413
Net income	335,694	306,301	38,769	74,898	(345,070)	410,592
Other comprehensive income (loss):						
Net deferred hedge gains (losses), net of tax:						
Net deferred hedge losses	-	(265,142)	(17,023)	-	-	(282,165)
Tax benefits related to net deferred hedge losses	-	-	249	50,815	-	51,064
Net hedge losses included in net income	-	109,223	8,193	-	-	117,416
Translation adjustment	-	-	36,938	-	-	36,938
Comprehensive income (loss)	$ 335,694	$ 150,382	$ 67,126	$ 125,713	$ (345,070)	$ 333,845

CONSOLIDATING CONDENSED STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)
For the Year Ended December 31, 2002
(in thousands)

	Parent	Pioneer USA	Non-Guarantor Subsidiaries	Consolidated Income Tax Provision	Eliminations	Consolidated Total
Revenues and other income:						
Oil and gas	$ -	$ 527,189	$ 174,591	$ -	$ -	$ 701,780
Interest and other	-	8,214	3,008	-	-	11,222
Gain on disposition of assets, net	-	3,230	1,202	-	-	4,432
	-	538,633	178,801	-	-	717,434
Costs and expenses:						
Oil and gas production	-	165,669	33,901	-	-	199,570
Depletion, depreciation and amortization	-	139,822	76,553	-	-	216,375
Exploration and abandonments	-	62,982	22,912	-	-	85,894
General and administrative	1,323	37,723	9,356	-	-	48,402
Interest	17,451	76,820	1,544	-	-	95,815
Equity (income) loss from subsidiary	(52,580)	8,374	-	-	44,206	-
Other	7,093	4,879	27,630	-	-	39,602
	(26,713)	496,269	171,896	-	44,206	685,658
Income before income taxes	26,713	42,364	6,905	-	(44,206)	31,776
Income tax provision	-	-	(5,063)	-	-	(5,063)
Net income	26,713	42,364	1,842	-	(44,206)	26,713
Other comprehensive income (loss):						
Net deferred hedge gains (losses):						
Net deferred hedge losses	(4)	(156,396)	(25,228)	-	-	(181,628)
Tax benefits related to net deferred hedge losses	-	-	2,561	-	-	2,561
Net hedge (gains) losses included in net income	447	(10,352)	(2,519)	-	-	(12,424)
Translation adjustment	-	-	2,188	-	-	2,188
Comprehensive income (loss)	$ 27,156	$ (124,384)	$ (21,156)	$ -	$ (44,206)	$ (162,590)

CONSOLIDATING CONDENSED STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)
For the Year Ended December 31, 2001
(in thousands)

	Parent	Pioneer USA	Non-Guarantor Subsidiaries	Consolidated Income Tax Provision	Eliminations	Consolidated Total
Revenues and other income:						
Oil and gas	$ -	$ 626,964	$ 220,058	$ -	$ -	$ 847,022
Interest and other	368	14,415	6,995	-	-	21,778
Gain (loss) on disposition of assets, net	-	8,524	(843)	-	-	7,681
	368	649,903	226,210	-	-	876,481
Costs and expenses:						
Oil and gas production	-	168,287	41,377	-	-	209,664
Depletion, depreciation and amortization	-	135,838	86,794	-	-	222,632
Exploration and abandonments	-	73,649	54,257	-	-	127,906
General and administrative	804	25,476	10,688	-	-	36,968
Interest	31,261	83,473	17,224	-	-	131,958
Equity (income) loss from subsidiary	(135,459)	5,588	-	-	129,871	-
Other	3,753	9,247	30,341	-	-	43,341
	(99,641)	501,558	240,681	-	129,871	772,469
Income (loss) before income taxes	100,009	148,345	(14,471)	-	(129,871)	104,012
Income tax provision	-	(783)	(3,220)	(13)	-	(4,016)
Net income (loss)	100,009	147,562	(17,691)	(13)	(129,871)	99,996
Other comprehensive income (loss):						
Net deferred hedge gains (losses):						
Transition adjustment	-	(172,007)	(25,437)	-	-	(197,444)
Net deferred hedge gains (losses)	(578)	364,051	31,824	-	-	395,297
Tax provisions related to net deferred hedge gains	-	-	(2,293)	-	-	(2,293)
Net hedge (gains) losses included in net income available for sale securities	135	(8,595)	13,946	-	-	5,486
Net unrealized gains (losses) on available for sale securities:						
Net unrealized available for sale securities holding losses	-	(45)	-	-	-	(45)
Net available for sale securities gains included in net income	-	(8,109)	-	-	-	(8,109)
Translation adjustment	-	-	(11,173)	-	-	(11,173)
Comprehensive income (loss)	$ 99,566	$ 322,857	$ (10,824)	$ (13)	$ (129,871)	$ 281,715

CONSOLIDATING CONDENSED STATEMENT OF CASH FLOWS
For the Year Ended December 31, 2003
(in thousands)

	Parent	Pioneer USA	Non-Guarantor Subsidiaries	Consolidated Total
Cash flows from operating activities:				
Net cash provided by operating activities	$ 59,761	$ 491,890	$ 212,028	$ 763,679
Cash flows from investing activities:				
Proceeds from disposition of assets	18,267	16,749	682	35,698
Additions to oil and gas properties	-	(478,280)	(209,853)	(688,133)
Other property (additions) dispositions, net	-	(14,748)	4,883	(9,865)
Net cash provided by (used in) investing activities	18,267	(476,279)	(204,288)	(662,300)
Cash flows from financing activities:				
Borrowings under long-term debt	264,725	-	-	264,725
Principal payments on long-term debt	(370,262)	-	-	(370,262)
Payment of other liabilities	-	(13,169)	(886)	(14,055)
Deferred loan fees	(2,799)	-	-	(2,799)
Purchase of treasury stock	(2,349)	-	-	(2,349)
Stock options exercised and employee stock purchases	33,020	-	-	33,020
Net cash used in financing activities	(77,665)	(13,169)	(886)	(91,720)
Net increase in cash and cash equivalents	363	2,442	6,854	9,659
Effect of exchange rate changes on cash and cash equivalents	-	-	1,150	1,150
Cash and cash equivalents, beginning of period	6	1,783	6,701	8,490
Cash and cash equivalents, end of period	$ 369	$ 4,225	$ 14,705	$ 19,299

CONSOLIDATED CONDENSED STATEMENT OF CASH FLOWS
For the Year Ended December 31, 2002
(in thousands)

	Parent	Pioneer USA	Non-Guarantor Subsidiaries	Consolidated Total
Cash flows from operating activities:				
Net cash provided by (used in) operating activities	$ (327,185)	$ 406,939	$ 252,491	$ 332,245
Cash flows from investing activities:				
Proceeds from disposition of assets	31,994	86,703	153	118,850
Additions to oil and gas properties	-	(365,981)	(248,717)	(614,698)
Other property (additions) dispositions, net	-	(13,171)	888	(12,283)
Net cash provided by (used in) investing activities	31,994	(292,449)	(247,676)	(508,131)
Cash flows from financing activities:				
Borrowings under long-term debt	529,805	-	-	529,805
Principal payments on long-term debt	(481,783)	-	-	(481,783)
Common stock issuance proceeds, net of issuance costs	236,000	-	-	236,000
Payment of other liabilities	-	(123,607)	(638)	(124,245)
Deferred loan fees/issuance costs	(3,293)	-	-	(3,293)
Stock options exercised and employee stock purchases	14,389	-	-	14,389
Net cash provided by (used in) financing activities	295,118	(123,607)	(638)	170,873
Net increase (decrease) in cash and cash equivalents	(73)	(9,117)	4,177	(5,013)
Effect of exchange rate changes on cash and cash equivalents	-	-	(831)	(831)
Cash and cash equivalents, beginning of period	79	10,900	3,355	14,334
Cash and cash equivalents, end of period	$ 6	$ 1,783	$ 6,701	$ 8,490

CONSOLIDATING CONDENSED STATEMENT OF CASH FLOWS
For the Year Ended December 31, 2001
(in thousands)

	Parent	Pioneer USA	Non-Guarantor Subsidiaries	Consolidated Total
Cash flows from operating activities:				
Net cash provided by (used in) operating activities	$ (10,503)	$ 307,776	$ 178,327	$ 475,600
Cash flows from investing activities:				
Cash acquired in acquisition, net of fees paid	-	11,119	-	11,119
Proceeds from disposition of assets	21,170	75,816	16,467	113,453
Additions to oil and gas properties	-	(336,753)	(192,970)	(529,723)
Other property additions, net	-	(10,717)	(6,873)	(17,590)
Net cash provided by (used in) investing activities	21,170	(260,535)	(183,376)	(422,741)
Cash flows from financing activities:				
Borrowings under long-term debt	328,331	-	-	328,331
Principal payments on long-term debt	(333,410)	-	-	(333,410)
Borrowing under (payment of) other liabilities	-	(54,728)	1,291	(53,437)
Purchase of treasury stock	(13,028)	-	-	(13,028)
Stock options exercised and employee stock purchases	7,504	-	-	7,504
Net cash provided by (used in) financing activities	(10,603)	(54,728)	1,291	(64,040)
Net increase (decrease) in cash and cash equivalents	64	(7,487)	(3,758)	(11,181)
Effect of exchange rate changes on cash and cash equivalents	-	-	(644)	(644)
Cash and cash equivalents, beginning of period	15	18,387	7,757	26,159
Cash and cash equivalents, end of period	$ 79	$ 10,900	$ 3,355	$ 14,334

PIONEER NATURAL RESOURCES COMPANY

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2003, 2002 and 2001

Capitalized Costs

	December 31, 2003	December 31, 2002
	(in thousands)	
Oil and Gas Properties:		
Proved	$ 4,983,558	$ 4,252,897
Unproved	179,825	219,073
Capitalized costs for oil and gas properties	5,163,383	4,471,970
Less accumulated depletion	(1,676,136)	(1,303,541)
Net capitalized costs for oil and gas properties	$ 3,487,247	$ 3,168,429

Costs Incurred for Oil and Gas Producing Activities (a)

	Property Acquisition Costs		Exploration Costs	Development Costs	Total Costs Incurred
	Proved	Unproved			
			(in thousands)		
Year Ended December 31, 2003:					
United States	$ 130,876	$ 12,264	$ 191,809	$ 228,064	$ 563,013
Argentina	97	1,787	24,893	25,361	52,138
Canada	63	5,028	24,899	23,040	53,030
Africa and other	-	910	33,212	20,697	54,819
Total costs incurred	$ 131,036	$ 19,989	$ 274,813	$ 297,162	$ 723,000
Year Ended December 31, 2002:					
United States	$ 156,736	$ 34,048	$ 72,831	$ 269,945	$ 533,560
Argentina	12	51	14,530	20,528	35,121
Canada	457	2,329	9,992	20,728	33,506
Africa and other	-	1,843	34,125	34,300	70,268
Total costs incurred	$ 157,205	$ 38,271	$ 131,478	$ 345,501	$ 672,455
Year Ended December 31, 2001:					
United States	$ 132,793	$ 19,572	$ 129,639	$ 172,225	$ 454,229
Argentina	13,182	2,465	36,237	46,427	98,311
Canada	29	97	12,707	23,215	36,048
Africa and other	706	1,960	41,446	13,860	57,972
Total costs incurred	$ 146,710	$ 24,094	$ 220,029	$ 255,727	$ 646,560

(a) The Company has not included asset retirement obligation accruals in the costs incurred for oil and gas producing activities presented in the table above. During the years ended December 31, 2003 and 2001, the Company accrued $46.7 million and $1.0 million of asset retirement obligations, respectively, associated with new wells and changes in estimates. The Company did not accrue any increases to asset retirement obligations during the year ended December 31, 2002. See Notes B and L for additional information regarding the Company's asset retirement obligations.

PIONEER NATURAL RESOURCES COMPANY

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2003, 2002 and 2001

Results of Operations

Information about the Company's results of operations for oil and gas producing activities by geographic operating segment is presented in Note R of the accompanying Notes to Consolidated Financial Statements.

Reserve Quantity Information

The estimates of the Company's proved oil and gas reserves as of December 31, 2003 and 2002, which are located in the United States, Argentina, Canada, Gabon, South Africa and Tunisia, were based on evaluations audited by independent petroleum engineers with respect to the Company's major properties and prepared by the Company's engineers with respect to all other properties. The estimates of the Company's proved oil and gas reserves as of December 31, 2001 were prepared by the Company's engineers. Reserves were estimated in accordance with guidelines established by the SEC and the Financial Accounting Standards Board, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements. The reserve estimates as of December 31, 2003, 2002 and 2001 utilize respective oil prices of $31.10, $29.67 and $18.88 per Bbl (reflecting adjustments for oil quality), respective NGL prices of $20.26, $19.01 and $11.58 per Bbl, and respective gas prices of $4.23, $3.37 and $2.21 per Mcf (reflecting adjustments for Btu content, gas processing and shrinkage).

Oil and gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

The following table provides a rollforward of total proved reserves by geographic area and in total for the years ended December 31, 2003, 2002 and 2001, as well as proved developed reserves by geographic area and in total as of the beginning and end of each respective year:

PIONEER NATURAL RESOURCES COMPANY

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2003, 2002 and 2001

Oil and Gas Producing Activities:

	2003			2002			2001		
Total Proved Reserves:	**Oil & NGLs (MBbls)**	**Gas (MMcf)**	**MBOE**	**Oil & NGLs (MBbls)**	**Gas (MMcf)**	**MBOE**	**Oil & NGLs (MBbls)**	**Gas (MMcf)**	**MBOE**
UNITED STATES									
Balance, January 1	337,631	1,483,971	584,960	279,146	1,474,090	524,829	266,802	1,354,327	492,523
Revisions of previous estimates	36,823	94,759	52,616	61,529	5,983	62,525	(1,179)	41,039	5,661
Purchases of minerals-in-place	4,422	57,124	13,942	8,634	83,361	22,528	24,943	63,113	35,462
New discoveries and extensions	250	80,769	13,712	4,364	5,349	5,255	4,442	93,220	19,979
Production	(16,375)	(162,647)	(43,483)	(16,042)	(84,812)	(30,177)	(15,862)	(77,609)	(28,796)
Balance, December 31	362,751	1,553,976	621,747	337,631	1,483,971	584,960	279,146	1,474,090	524,829
ARGENTINA									
Balance, January 1	31,532	532,081	120,211	35,669	471,150	114,193	35,843	408,282	103,890
Revisions of previous estimates	2,027	44,064	9,372	(4,954)	47,829	3,017	(932)	4,460	(189)
Purchases of minerals-in-place	-	-	-	-	-	-	170	31,700	5,453
New discoveries and extensions	3,562	8,068	4,907	3,985	41,652	10,927	4,354	58,538	14,110
Production	(3,652)	(34,357)	(9,378)	(3,168)	(28,550)	(7,926)	(3,766)	(31,830)	(9,071)
Balance, December 31	33,469	549,856	125,112	31,532	532,081	120,211	35,669	471,150	114,193
CANADA									
Balance, January 1	2,361	119,328	22,249	2,659	132,061	24,669	4,066	132,919	26,219
Revisions of previous estimates	344	(14,920)	(2,143)	24	(1,150)	(167)	212	15,067	2,723
New discoveries and extensions	73	4,630	845	68	6,070	1,080	81	5,644	1,022
Production	(371)	(15,209)	(2,906)	(390)	(17,653)	(3,333)	(671)	(18,426)	(3,742)
Sales of minerals-in-place	-	-	-	-	-	-	(1,029)	(3,143)	(1,553)
Balance, December 31	2,407	93,829	18,045	2,361	119,328	22,249	2,659	132,061	24,669
AFRICA									
Balance, January 1	9,320	-	9,320	7,685	-	7,685	5,552	-	5,552
Revisions of previous estimates	(1,817)	-	(1,817)	790	-	790	-	-	-
Purchases of minerals-in-place	-	-	-	-	-	-	2,133	-	2,133
New discoveries and extensions	17,374	-	17,374	845	-	845	-	-	-
Production	(723)	-	(723)	-	-	-	-	-	-
Balance, December 31	24,154	-	24,154	9,320	-	9,320	7,685	-	7,685
TOTAL									
Balance, January 1	380,844	2,135,380	736,740	325,159	2,077,301	671,376	312,263	1,895,528	628,184
Revisions of previous estimates (a)	37,377	123,903	58,028	57,389	52,662	66,165	(1,899)	60,566	8,195
Purchases of minerals-in-place	4,422	57,124	13,942	8,634	83,361	22,528	27,246	94,813	43,048
New discoveries and extensions	21,259	93,467	36,838	9,262	53,071	18,107	8,877	157,402	35,111
Production	(21,121)	(212,213)	(56,490)	(19,600)	(131,015)	(41,436)	(20,299)	(127,865)	(41,609)
Sales of minerals-in-place	-	-	-	-	-	-	(1,029)	(3,143)	(1,553)
Balance, December 31	422,781	2,197,661	789,058	380,844	2,135,380	736,740	325,159	2,077,301	671,376
Proved Developed Reserves:									
United States	209,948	1,067,701	387,899	196,893	1,027,750	368,184	206,922	1,081,592	387,188
Argentina	22,180	402,640	89,287	28,248	341,967	85,243	22,679	345,281	80,226
Canada	2,042	90,003	17,042	2,086	94,607	17,854	2,930	80,953	16,422
January 1	234,170	1,560,344	494,228	227,227	1,464,324	471,281	232,531	1,507,826	483,836
United States	209,349	1,202,264	409,727	209,948	1,067,701	387,899	196,893	1,027,750	368,184
Argentina	21,149	352,660	79,926	22,180	402,640	89,287	28,248	341,967	85,243
Canada	2,312	86,500	16,728	2,042	90,003	17,042	2,086	94,607	17,854
Africa	6,817	-	6,817	-	-	-	-	-	-
December 31	239,627	1,641,424	513,198	234,170	1,560,344	494,228	227,227	1,464,324	471,281

(a) The revisions of previous estimates above, include revisions attributable to changes in commodity prices totaling a 3,429 MBOE increase, a 28,643 MBOE increase and a 24,970 MBOE decrease for the years ended December 31, 2003, 2002 and 2001, respectively.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows is computed by applying year-end prices of oil and gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and gas reserves less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows. Future income taxes are calculated by comparing undiscounted future cash flows to the tax basis of oil and gas properties plus available carryforwards and credits and applying the current tax rates to the difference. The discounted future cash flow estimates do not include the effects of the Company's commodity hedging contracts. Utilizing December 31, 2003 commodity prices held constant over each hedge contract's term, the net present value of the Company's hedge contracts, less associated estimated income taxes and discounted at 10 percent, was a liability of approximately $191.0 million.

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of oil and gas properties. Estimates of fair value should also consider probable reserves, anticipated future oil and gas prices, interest rates, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair value is necessarily subjective and imprecise.

The following tables provide the standardized measure of discounted future cash flows by geographic area and in total for the years ended December 31, 2003, 2002 and 2001, as well as a rollforward in total for each respective year:

PIONEER NATURAL RESOURCES COMPANY

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2003, 2002 and 2001

	Year Ended December 31,		
	2003	2002	2001
		(in thousands)	
UNITED STATES			
Oil and gas producing activities:			
Future cash inflows	$ 18,239,318	$ 15,161,717	$ 8,222,573
Future production costs	(5,918,790)	(4,830,294)	(3,231,730)
Future development costs	(1,188,394)	(864,386)	(735,984)
Future income tax expense	(3,057,968)	(2,325,946)	(598,612)
	8,074,166	7,141,091	3,656,247
10% annual discount factor	(4,276,678)	(3,684,400)	(1,691,118)
Standardized measure of discounted future cash flows	$ 3,797,488	$ 3,456,691	$ 1,965,129
ARGENTINA			
Oil and gas producing activities:			
Future cash inflows	$ 1,257,068	$ 986,716	$ 1,070,664
Future production costs	(233,399)	(175,938)	(227,435)
Future development costs	(136,663)	(84,669)	(144,604)
Future income tax expense	(161,683)	(143,845)	(45,140)
	725,323	582,264	653,485
10% annual discount factor	(282,205)	(242,158)	(262,334)
Standardized measure of discounted future cash flows	$ 443,118	$ 340,106	$ 391,151
CANADA			
Oil and gas producing activities:			
Future cash inflows	$ 520,976	$ 502,260	$ 301,002
Future production costs	(91,675)	(89,246)	(73,601)
Future development costs	(11,551)	(22,294)	(27,050)
Future income tax expense	(72,895)	(87,363)	(10,771)
	344,855	303,357	189,580
10% annual discount factor	(126,436)	(104,345)	(59,995)
Standardized measure of discounted future cash flows	$ 218,419	$ 199,012	$ 129,585
AFRICA			
Oil and gas producing activities:			
Future cash inflows	$ 713,459	$ 279,896	$ 149,777
Future production costs	(212,615)	(95,216)	(73,697)
Future development costs	(261,413)	(26,770)	(54,281)
Future income tax expense	(17,062)	(10,912)	-
	222,369	146,998	21,799
10% annual discount factor	(98,141)	(16,255)	(7,338)
Standardized measure of discounted future cash flows	$ 124,228	$ 130,743	$ 14,461
TOTAL			
Oil and gas producing activities:			
Future cash inflows	$ 20,730,821	$ 16,930,589	$ 9,744,016
Future production costs	(6,456,479)	(5,190,694)	(3,606,463)
Future development costs (a)	(1,598,021)	(998,119)	(961,919)
Future income tax expense	(3,309,608)	(2,568,066)	(654,523)
	9,366,713	8,173,710	4,521,111
10% annual discount factor	(4,783,460)	(4,047,158)	(2,020,785)
Standardized measure of discounted future cash flows	$ 4,583,253	$ 4,126,552	$ 2,500,326

(a) Includes $208.1 million of undiscounted future asset retirement expenditures estimated as of December 31, 2003 using current estimates of future abandonment costs. See Notes B and L for corresponding information regarding the Company's discounted asset retirement obligations.

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2003, 2002 and 2001

Oil and Gas Producing Activities	Year Ended December 31, 2003	2002 (in thousands)	2001
Oil and gas sales, net of production costs	$(1,136,520)	$ (489,338)	$ (631,365)
Net changes in prices and production costs	670,165	2,042,575	(4,528,168)
Extensions and discoveries	413,777	152,253	184,454
Development costs incurred during the period	202,396	262,469	239,156
Sales of minerals-in-place	-	-	(23,372)
Purchases of minerals-in-place	198,442	187,460	201,535
Revisions of estimated future development costs	(444,726)	(387,404)	(429,365)
Revisions of previous quantity estimates	458,468	527,987	40,771
Accretion of discount	514,608	250,033	701,943
Changes in production rates, timing and other	(71,557)	99,722	(274,689)
Change in present value of future net revenues	805,053	2,645,757	(4,519,100)
Net change in present value of future income taxes	(348,352)	(1,019,531)	1,373,924
	456,701	1,626,226	(3,145,176)
Balance, beginning of year	4,126,552	2,500,326	5,645,502
Balance, end of year	$ 4,583,253	$ 4,126,552	$ 2,500,326

Selected Quarterly Financial Results

The following table provides selected quarterly financial results for the years ended December 31, 2003 and 2002:

	Quarter First	Second (in thousands, except per share data)	Third (a)	Fourth
2003				
Oil and gas revenues	$ 281,156	$ 339,954	$ 332,515	$ 345,022
Total revenues and other income	$ 285,295	$ 341,318	$ 332,909	$ 352,673
Total costs and expenses	$ 214,184	$ 261,503	$ 240,991	$ 264,741
Net income:				
Income before cumulative effect of change in accounting principle	$ 68,807	$ 77,185	$ 191,813	$ 57,374
Cumulative effect of change in accounting principle, net of tax	15,413	-	-	-
Net income	$ 84,220	$ 77,185	$ 191,813	$ 57,374
Net income per share:				
Basic:				
Income before cumulative effect of change in accounting principle	$ .59	$ .66	$ 1.64	$ .49
Cumulative effect of change in accounting principle, net of tax	.13	-	-	-
Net income	$ .72	$ .66	$ 1.64	$ .49
Diluted:				
Income before cumulative effect of change in accounting principle	$ .58	$ .65	$ 1.62	$ .48
Cumulative effect of change in accounting principle, net of tax	.13	-	-	-
Net income	$ .71	$ .65	$ 1.62	$ .48
2002				
Oil and gas revenues	$ 165,539	$ 172,430	$ 168,317	$ 195,494
Total revenues and other income	$ 166,658	$ 174,338	$ 178,753	$ 197,685
Total costs and expenses	$ 169,027	$ 161,759	$ 177,454	$ 177,418
Net income (loss)	$ (1,959)	$ 11,142	$ (890)	$ 18,420
Net income (loss) per share:				
Basic	$ (.02)	$ .10	$ (.01)	$ .16
Diluted	$ (.02)	$ .10	$ (.01)	$ .16

(a) The Company's third quarter results for 2003 include a $104.7 million adjustment to reduce United States deferred tax asset valuation allowances. See Note P for additional information regarding income taxes.

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

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required in response to this item is set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held on May 13, 2004 and is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required in response to this item is set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held on May 13, 2004 and is incorporated herein by reference.

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

The information required in response to this item is set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held on May 13, 2004 and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by Item 201(d) of Regulation S-K in response to this item is provided in "Item 5. Market for Registrant's Common Equity and Related Stockholder Matters". The information required by Item 403 of Regulation S-K in response to this item is set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held on May 13, 2004 and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required in response to this item is set forth in the Company's definitive proxystatement for the annual meeting of stockholders to be held on May 13, 2004 and is incorporated herein by reference.

PART IV

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

(a) Listing of Financial Statements and Exhibits

Financial Statements

The following consolidated financial statements of the Company are included in "Item 8. Financial Statements and Supplementary Data":

Independent Auditors' Report
Consolidated Balance Sheets as of December 31, 2003 and 2002
Consolidated Statements of Operations for the Years Ended December 31, 2003, 2002 and 2001
Consolidated Statements of Stockholders' Equity for the Years Ended December 31, 2003, 2002 and 2001
Consolidated Statements of Cash Flows for the Years Ended December 31, 2003, 2002 and 2001
Consolidated Statements of Comprehensive Income (Loss) for the Years Ended December 31, 2003, 2002 and 2001
Notes to Consolidated Financial Statements
Unaudited Supplementary Information

(b) Reports on Form 8-K

During the three months ended December 31, 2003, the Company filed one Current Report on Form 8-K dated October 30, 2003. The Company's October 30, 2003 Form 8-K provided, under Items 7 and 12, the Company's news release including attached schedules dated October 30, 2003 that announced the Company's financial and operating results for the three and nine month periods ended September 30, 2003, an operational update and the Company's fourth quarter 2003 financial outlook.

(c) Exhibits

The exhibits to this Report required to be filed pursuant to Item 15(c) are included in the Company's Form 10-K filed with the SEC on February 3, 2004.

(d) Financial Statement Schedules

No financial statement schedules are required to be filed as part of this Report or they are inapplicable.

SHAREHOLDER INFORMATION:

STOCK EXCHANGE LISTING
Common Stock
Ticker symbol: PXD
New York Stock Exchange

CORPORATE HEADQUARTERS
Pioneer Natural Resources Company
5205 N. O'Connor Blvd., Suite 900
Irving, TX 75039
(972) 444-9001

INTERNET ADDRESS
www.pioneernrc.com

STOCK TRANSFER AGENT AND REGISTRAR
Communication concerning the transfer or exchange of shares, lost certificates or change of address should be directed to:

Continental Stock Transfer & Trust Company
17 Battery Place, 8th Floor
New York, NY 10004
(888) 509-5586

Internet Address: www.continentalstock.com
E-Mail: pioneer@continentalstock.com

ANNUAL MEETING
The Annual Meeting of stockholders will be held Thursday, May 13, 2004 at 9:00 a.m. at the Marriott Las Colinas Hotel, 223 W. Las Colinas Blvd., Irving, Texas.

INFORMATION REQUESTS
To receive additional copies of the Annual Report on Form 10-K as filed with the Securities and Exchange Commission, to obtain other Pioneer publications or to be placed on the direct mailing list please contact:

Pioneer Natural Resources Company
Investor Relations
5205 N. O'Connor Blvd., Suite 900
Irving, TX 75039
(972) 969-3583
ir@pioneernrc.com

INVESTOR RELATIONS / MEDIA CONTACT
Shareholders, portfolio managers, brokers and securities analysts seeking information concerning Pioneer's operations or financial condition are encouraged to contact Susan Spratlen, Vice President, Investor Relations and Communication at (972) 444-9001.

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Pioneer Natural Resources Canada Inc.
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Pioneer Natural Resources (Argentina) S.A.
Güimar J. Vaca Coca, President
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Telephone: 5411 4312-9081

Pioneer Natural Resources South Africa (PTY) Limited
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Telephone: 27 21 425-5012

Pioneer Resources Gabon – Olowi Ltd.
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Pioneer Natural Resources Tunisia LTD
Hashim Alkhersan, Manager
La Residence Lakeo-3rd Floor
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Les Berges du Lac
1053 - Tunis, Tunisia
Telephone: 216-71-960 885

BOARD OF DIRECTORS:

(PICTURED ABOVE, IN ORDER FROM LEFT TO RIGHT, TOP TO BOTTOM)

Scott D. Sheffield
Chairman, President
and Chief Executive Officer

Charles E. Ramsey, Jr. [1,3,4]
Financial Consultant

James L. Houghton [2,4]
Retired Senior Tax Partner
Ernst & Young, L.L.P.

Jerry P. Jones [2,4]
Retired Shareholder and Of Counsel
Thompson & Knight, P.C.

Edison C. Buchanan [3,4]
Former Managing Director
Credit Suisse First Boston

Robert A. Solberg [2,4]
Retired Vice President
Texaco, Inc.

Linda K. Lawson [2,4]
Former Vice President
Williams Companies

James R. Baroffio [3,4]
Former President
Chevron Canada Resources

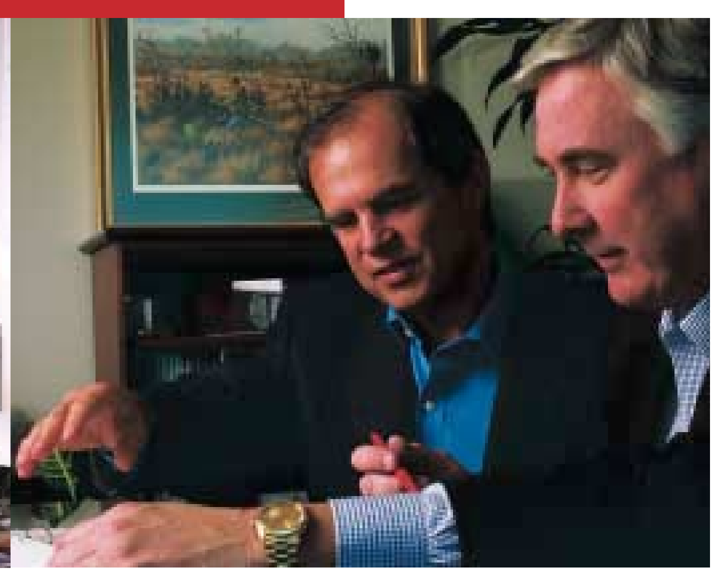
R. Hartwell Gardner [2,4]
Retired Treasurer
Mobil Corporation

[1] **Lead Director**
[2] **Audit Committee**
[3] **Compensation Committee**
[4] **Nominating and Corporate Governance Committee**

Corporate Officers on page 9.

"The members of our board have always taken their responsibility to shareholders seriously, and they bring to the table knowledge and experience that is both broad and deep. We appreciate their willingness to roll up their sleeves and join us in our commitment to laying out the right course for Pioneer."

SCOTT SHEFFIELD



PIONEER
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