Devon Energy
2006 Annual Report

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Carrie Fyfe
Jay Gabbard
John Gabert
Phillip Gaboury
Gwen Gabriel
Kathy Gabrielson
Polina Gaddy
Richard Gafiuk
Beverley Gage
Marcel Gagne
Brandon Gainer
Mervin Galbraith
Danny Gallenbeck
Starleng Gallope
Janet Galloway
Blair Gamble
Waldemar Gamp
Kim Gann
Vidya Ganness
Michelle Gantt
Jose Garate
Tom Garbs
Joe Garcia
Joel Garcia
Judith Garcia
Michael Garcia
Ruben Garcia
Norma Garcia-Slajer
Al Gardiner
George Gardiner
Doug Garrard
Heather Garrett
Kelly Garrett
Lynn Garrett
Barney Gary
Douglas Gary
Michael Gary
Alberto Garza
Ernest Garza
Lamar Gaspard
Dewayne Gaught
Clyde Gautreau
Judith Gavan
Raphael Gay-De-Montella
Tim Gaydos
J. Nick Geib
David Geis
Larry Gelbaugh
Orry Gelowitz
Carol Gennarelli
Kirk Geno
Charles Gentry
Dale George
David George
Mircea Georgescu
Radu Georgescu
Jeff Gephart
Martha Gerdes
John Gerding
John Jr Gerich
Kirk Gerich
John Gerlitz
Ken German
Mark German
Taylor German
David Germscheid
Michal Gerov
Stan Gerow
Rod Gertson
Stan Geurin
Nick Gibbens
Rosalind Gibson
Tatiana Gibson
Tina Gibson
Heidi Giesbrecht
Mark Giesbrecht
Darrell Gilbert
Ed Gilbert
Vicky Gillespie
Russell Gillett
Carolyn Gilley
Angela Gingera
Deena Girdner
Paul Girouard
Richard Giroux
Carola Giudicelli
Jan Glasgow
Ed Glass
Ray Glidewell
David Glover
Andre Godin
Jeff Goffin
Kris Goforth
Patrick Gohlke
Sherman Goines
Diana Goldstein
Karen Golonka
Francis Gomes
Alma Gomez
Jesse Gomez
Lawrence Gomez
Albert Gonzales
Terry Gonzales
Abraham Gonzalez
Magdalena Gonzalez
Pilar Gonzalez
Kevin Good
Craig Goodall
Krystal Goodman
Craig Goodrich
Lana Goodrich
Rickey Goodson
John Goodspeed
Shannon Goodwin
Alan Gopen
Edward Gorden
Shane Gordon
Wendy Gordon
Jason Goss
Mark Goss
Shawn Goss
Jennifer Gottsch
Paul Gould
Philip Gould
Darrin Gowing
Kerri Grabowsky
Cameron Grace

Tim Graff
Anthony Graham
Candi Graham
Gary Graham
Jennifer Graham
John Graham
Sean Graham
Veronica Graham
Jannette Granstaff
Greg Grassell
Dean Graves
Galen Gray
Jason Gray
Ken Gray
Leslie Gray
Stephanie Greaser
Vicki Greear
Allan Green
Bill Green
Clayton Green
Earl Green
Gregory Green
Larry Green
Monica Green
Paul Green
Suzanne Green
Sylvia Green
Tim Green
Dale Greenfeather
Alan Greenfield
Michael Greenhow
Bill Greenlees
Ryan Greer
Nicholas Gregg
Betty Gregory
J.R. Gregory
Matt Gregory
Lee Greiner
Glenn Gresham
Mark Gresko
Mark Gress
Evelyn Grey
Vince Gribble
Michael Griffin
Joel Grillot
Aaron Grimeau
Rhonda Grimes
Jason Grimm
Mark Grinnell
Lauren Grissom
Letitia Groce
Karin Groepper
Aaron Gross
Albert Gross
Jonathon Gross
Mary Gross
Eric Grossman
Joe Grossman
John Grounds
Roxanne Groves
Sam Groves
Joan Grozell
Doug Grubb
Michelle Guanzo-Reyes
Caroline Guay
Sonya Guenther
Jesse Guerrero
Raquel Guerrero
Gary Guerrieri
Joel Guichard
Cathy Guidry
Christopher Guidry
Wendell Guidry
Floyd Guillory
Miller Guillory
Jeff Guillot
Jay Guilmette
Janice Gunn
George Gurr
Eric Gurule
Ed Guseman
Elham Gushtasbi
Jeff Gussie
Stacey Gustafson
Linda Guthrie
Mike Gutkoski
Veronica Guzman
Thu Ba Ha
Debra Haaland
Jason Haas
Ziad Haddad
Steve Hadden
Jim Hager
Teresa Hager
Zack Hager
Kelly Hagg
Adina Hagi-Memet
April Hague
Allison Hahn
Melvin Hakes
Rick Hale
Nancy Haley
Amos Hall
Brad Hall
David Hall
James Hall
Jeff Hall
Kay Hall
Paula Hall
Robin Hallock
Troy Halsall
Bev Halter
Jackson Halter
Jason Hamel
Percy Hamilton
Randy Hamilton
Sarah Hammond
David Hamon
Blaine Hampton
Steve Hamrick
Wayne Han
Tim Hancsicsak
Rusty Hand
Tim Hand
Joe Handley
Wes Handley
Herman Handstede
Michael Hankins
Reagan Hanks

resource full

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Devon's employees are our most valued resource. The names of each of our 4,692 employees are printed on the inside front cover and on pages 6 and 32 of this annual report.

Resource Full, the theme of this annual report, was inspired by an entry from Karen Price in Devon's Portland, Texas, field office. Nearly 1,200 entries were submitted by employees in our annual contest to select the theme.

Corporate Profile Devon is one of North America's leading independent oil and gas exploration and production companies. Devon's operations are focused primarily in the United States and Canada; however, the company also explores for and produces oil and natural gas in select international areas. We also own natural gas pipelines and treatment facilities in many of our producing areas, making us one of North America's larger processors of natural gas liquids. Devon is included in the S&P 500 Index and trades on the New York Stock Exchange under the ticker symbol DVN.

Letter to Shareholders

J. LARRY NICHOLS
CHAIRMAN AND CHIEF EXECUTIVE OFFICER

Dear Fellow Shareholders: 2006 was a year of outstanding achievements for Devon. Earnings per share and cash flow from operations reached new highs. We increased oil and gas reserves to the highest levels in our history, and we made important strides in both high-impact exploration and low-risk development projects that will fuel Devon's future growth.

Gulf of Mexico Success Brings Worldwide Acclaim

The operational high point of our year was the successful production test of the Jack No. 2 well in the Gulf of Mexico's Lower Tertiary trend. During testing, the Jack No. 2 well flowed 6,000 barrels of oil per day from just 40% of the hydrocarbon-bearing column. The results indicate that Lower Tertiary reservoirs will produce at high rates providing compelling evidence that Devon's deepwater Lower Tertiary reservoirs can be profitably developed.

When Devon and co-owners Chevron and Statoil released news of the Jack test on September 5, 2006, the world awoke to the tremendous potential of the Lower Tertiary trend. Pundits applauded it as a major new energy source for the United States. Some called it the biggest find since Prudhoe Bay. Time will judge the accuracy of such predictions, but we believe Devon's proprietary position in the Lower Tertiary could, over time, double or even triple Devon's current proved reserve base of 2.4 billion oil-equivalent barrels.

The media's excitement and the investment community's favorable reaction to the Jack announcement were gratifying and validated the merits of Devon's long-term growth strategy. We have invested more than $2 billion over the past five years in high-impact, multi-year exploration projects. By their very nature, we knew these projects could not deliver oil and gas reserves, production or revenue in the near term. However, we believed the short-term sacrifice required to make these investments would be well worth the longer-term rewards. These investments will provide Devon and its shareholders with a steady stream of development projects over the next decade.

Brightening the glow of success following the Jack test was the added satisfaction of our fourth significant Lower Tertiary discovery. This discovery, known as Kaskida, appears to be even larger than Jack and also larger than our first two Lower Tertiary discoveries, Cascade and St. Malo. Furthermore, Kaskida extends the Lower Tertiary play into the deepwater Keathley Canyon federal lease area where we hold 12 additional exploratory prospects.

With four discoveries out of six attempts, our early success ratio in the Lower Tertiary is exceptional by historical standards. While we cannot count on this level of success going forward, it demonstrates that our seismic interpretation approach and depositional model for the Lower Tertiary are working well. We attribute this success to the skill and preparation of our highly-seasoned deepwater exploration teams.

We doubled our working interest in the Cascade discovery to 50% in 2006 and reached a decision to commercially develop the project. Cascade will likely be the first development in the Gulf of Mexico to employ an FPSO, or floating production, storage and offloading vessel. FPSO technology allows for the production of large oil reservoirs currently beyond the reach of existing pipelines. Our current plans call for Cascade to begin producing oil in late 2009.

Over the next several years we will explore other Lower Tertiary prospects with the aim of extending our impressive string of discoveries. We will also drill appraisal wells to further define and quantify the prizes we have found to date. These activities will provide the information necessary to move these projects into the development and production phases. Engineering and marketing plans for Jack and St. Malo could be finalized this year with first production in the 2011 to 2013 time frame.

Our mounting success in the Lower Tertiary trend and other areas in North America caused us to re-examine the high-impact exploration segment of our portfolio. In 2006, we made the decision to divest our assets in Egypt, and early this year we announced plans to exit West Africa. By doing so, we have the opportunity to further refine our focus. We believe we can redeploy our technical and financial resources from Africa more effectively to other parts of our business that can generate reserves and production growth more quickly. We expect to apply the proceeds of our African asset sales to invest in new projects, strengthen our balance sheet and repurchase shares to further enhance value per share.

Previous Investments Coming on Strong

Successful exploration projects ultimately move into the development phase. In 2007, we expect to achieve first production from three multi-year development projects: Polvo, Merganser and Jackfish. These projects are in addition to the full year of increased production we will receive from the ACG field in Azerbaijan. Devon's oil production from ACG increased dramatically in the fourth quarter of 2006, and we expect it to average more than 30,000 barrels per day in 2007.

Offshore Brazil, we are on track to deliver first production in mid-2007 from our 2004 Polvo oil discovery. Construction and fabrication of the $380 million Polvo facilities, in which Devon has a 60% working interest, progressed throughout 2006.

We have now completed most of the work necessary to bring our 50%-owned deepwater Merganser natural gas field on production in 2007. Merganser, a 2001 discovery, should begin producing into the Independence Hub in the eastern Gulf of Mexico around mid-year. Moored in 8,000 feet of water, the Independence Hub host facility will establish a water-depth record for Gulf gas production. Together, Merganser and Polvo will add about 35,000 oil-equivalent barrels to Devon's net daily production when fully operational.

In Canada, the 100% Devon-owned Jackfish thermal oil sands project is on schedule to begin producing in late 2007. Jackfish uses steam-injection technology, and Devon will be the first U.S.-based independent producer to complete such a project in Canada. When fully operational, we expect the initial phase of Jackfish to produce about 35,000 barrels of oil per day for 20 years or more. In addition, we are in the later stages of evaluating a look-alike project on adjacent acreage that would double Jackfish production to 70,000 barrels per day.

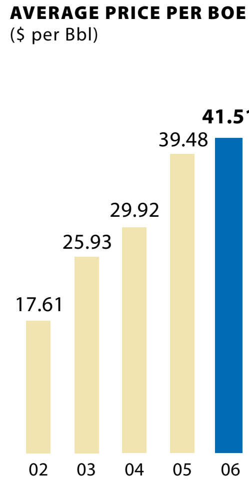
Elsewhere in Canada, we have elected to cut back on capital allocated to conventional natural gas projects. Rising costs in Canada, accentuated by the strengthening Canadian dollar, have hurt gas drilling economics. We expect this situation to correct itself in the next year or so. Until then, we will allocate our capital to other North American project areas where upward cost pressures have been less intense.

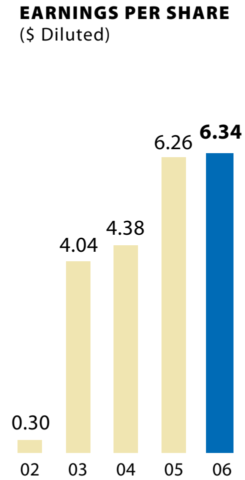
U.S. Onshore Projects Add Stability and Growth

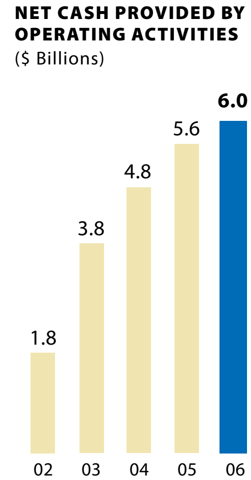
High-impact exploration is only part of Devon's long-term growth strategy. Repeatable, low-risk onshore oil and gas drilling is another important component. Notably in 2006, we substantially strengthened our position in the Barnett Shale, the largest gas field in Texas. The $2.2 billion acquisition of Chief Holdings in June extended Devon's lead as the top acreage holder and gas producer in the field. We expect to increase net gas production from our 736,000 Barnett Shale acres to about one billion cubic feet equivalent per day in 2009. To put this in perspective, one billion cubic feet per day is enough natural gas to heat more than five million homes and represents about 2% of total U.S. natural gas production.

We drilled our 600th horizontal well in the Barnett Shale in 2006, and the most recent of those wells were drilled with new generation rigs that can drill wells more quickly, safely and efficiently. Our 2006 activity drove Devon's Barnett Shale production up more than 25% during the year to over 700 million cubic feet per day in December.

The Barnett Shale is our largest asset, but it is just one of many in the United States and Canada. About 89% of our total oil and gas production in 2006 came from North America, where we drilled 2,427 wells with a 98% success rate. Devon is the largest U. S.-based independent producer in Canada and a leading producer in the states of New Mexico, Montana, Wyoming and Texas.







Devon's realized price for oil and gas climbed to $41.51 per equivalent barrel in 2006. This enabled the company to earn a record $6.34 per share and drove cash flow to a record $6 billion.

Production Growth Today and Tomorrow

What does all this operational success mean? First, it means significant production growth. We forecast production from continuing operations in 2007 at 219 to 221 million oil-equivalent barrels, excluding any production from the properties in Africa that we intend to divest. This is a 10% increase over the 200 million oil-equivalent barrels we produced in 2006, without Africa. We also anticipate about a 10% sequential production increase again in 2008.

Operational success also means growth in oil and gas reserves in the ground to be produced in future years. We added 427 million equivalent barrels from successful drilling in 2006. This does not include any contribution from the major discoveries we have made in the Lower Tertiary trend or additional development in the Jackfish area. The reserve additions for the Cascade, Jack, St. Malo and Kaskida projects, as well as any additional discoveries in the Lower Tertiary trend, will be recorded in future years. And Devon's Lower Tertiary inventory of untested deepwater Gulf of Mexico prospects represents billions of additional barrels of potential resources.

Focused on Performance

Rising costs are a challenge throughout the oil and gas industry. Competition for services, supplies and personnel are reflected in higher costs and tighter profit margins. Amid these challenges, Devon again delivered an outstanding financial performance in 2006. Net earnings topped $2.8 billion and per share earnings reached $6.34, the highest level in our history. Devon also continues to generate healthy levels of cash. Cash flow from operations reached $6 billion in 2006, another all-time high.

Exploration and production of oil and natural gas requires high levels of capital investment. We invested more than $5 billion on exploration and development projects in 2006 plus $2.2 billion in the purchase of the Chief properties. We plan to invest up to $5.3 billion on exploration and development projects in 2007. Ours is a capital-intensive business, and Devon is committed to making the investments necessary to remain a healthy and growing company.

I want to offer a note of special thanks to Duke Ligon, senior vice president and general counsel, who retired in January. Duke led Devon's Legal Department for 10 years, and we will miss his leadership and wise counsel. Lyndon Taylor has joined Devon's Executive Committee as Duke's replacement. Lyndon brings to Devon more than 20 years of legal and management experience and is a welcome addition to the Devon executive team.

As we enter 2007, I could not be more excited about Devon's future. The steps we took early in this decade to build a robust pipeline of future growth projects are paying off; we have the deepest inventory of investment opportunities in our history. The theme of this report is *Resource Full*. This refers to how we view the opportunities ahead of us and the capabilities of the company to execute those opportunities. It also reflects the creative spirit and resourcefulness of Devon's employees and business partners. It is these attributes that have put the company in the enviable position that we are in today. In this report, you will read comments from a variety of these employees and other stakeholders about Devon and its core values. I deeply appreciate the thoughts of these contributors and the positive reflection their words cast upon our entire organization.

J. LARRY NICHOLS
Chairman and Chief Executive Officer
March 20, 2007

Five-Year Highlights

YEAR ENDED DECEMBER 31,		2002	2003	2004	2005	2006	LAST YEAR CHANGE
FINANCIAL DATA (1) (Millions, except per share data)							
Total revenues	$	4,316	7,309	9,086	10,622	10,578	—
Total expenses and other income, net (2)		4,450	5,020	5,810	6,117	6,566	7%
Earnings (loss) before income taxes		(134)	2,289	3,276	4,505	4,012	(11%)
Total income tax expense (benefit)		(193)	527	1,095	1,606	1,189	(26%)
Earnings from continuing operations		59	1,762	2,181	2,899	2,823	(3%)
Earnings (loss) from discontinued operations		45	(31)	5	31	23	(26%)
Cumulative effect of change in accounting principle		—	16	—	—	—	N/M
Net earnings		104	1,747	2,186	2,930	2,846	(3%)
Preferred stock dividends		10	10	10	10	10	—
Net earnings applicable to common stockholders	$	94	1,737	2,176	2,920	2,836	(3%)
Net earnings per share:							
Basic	$	0.31	4.16	4.51	6.38	6.42	1%
Diluted	$	0.30	4.04	4.38	6.26	6.34	1%
Weighted average common shares outstanding:							
Basic		309	417	482	458	442	(3%)
Diluted		313	433	499	470	448	(5%)
Cash flow from continuing operating activities	$	1,726	3,771	4,789	5,514	5,936	8%
Cash flow from discontinued operating activities		28	(3)	27	98	57	(42%)
Net cash provided by operating activities	$	1,754	3,768	4,816	5,612	5,993	7%
Cash dividends per common share	$	0.10	0.10	0.20	0.30	0.45	50%
Closing common share price	$	22.95	28.63	39.03	62.54	67.08	7%

DECEMBER 31,		2002	2003	2004	2005	2006	LAST YEAR CHANGE
Total assets	$	16,225	27,162	30,025	30,273	35,063	16%
Debentures exchangeable into shares of Chevron Corporation common stock (3)	$	662	677	692	709	727	3%
Other long-term debt	$	6,900	7,903	6,339	5,248	4,841	(8%)
Stockholders' equity	$	4,653	11,056	13,674	14,862	17,442	17%
Working capital (deficit)	$	22	293	772	1,272	(1,433)	(213%)
PROPERTY DATA (1)							
Proved reserves (Net of royalties)							
Oil (MMBbls)		444	646	585	640	708	11%
Gas (Bcf)		5,836	7,316	7,493	7,296	8,356	15%
NGLs (MMBbls)		192	209	232	246	275	12%
Oil, Gas and NGLs (MMBoe)		1,609	2,074	2,065	2,102	2,376	13%

YEAR ENDED DECEMBER 31,	2002	2003	2004	2005	2006	LAST YEAR CHANGE
Production (Net of royalties)						
Oil (MMBbls)	42	60	74	62	55	(11%)
Gas (Bcf)	761	863	891	827	815	(1%)
NGLs (MMBbls)	19	22	24	24	23	(2%)
Oil, Gas and NGLs (MMBoe)	188	226	247	224	214	(4%)

(1) The year 2002 excludes results from Devon's operations in Indonesia, Argentina and Egypt that were discontinued in 2002. Devon acquired new assets in Egypt in the April 2003 Ocean merger. The years 2003 through 2006 exclude results from operations in Egypt that were discontinued in 2006. Revenues, expenses and production in 2003 include only eight and one-fourth months attributable to the Ocean merger and, in 2002, include only 11 and one-fourth months attributable to the Mitchell merger. All periods have been adjusted to reflect the two-for-one stock split that occurred on November 15, 2004.

(2) Includes other income, which is netted against other expenses.

(3) Debentures exchangeable into 14.2 million shares of Chevron common stock owned by Devon.

N/M Not a meaningful number.

Russell Hanna
Sandy Hanneld
Daniel Hansberger
Brad Hansen
Peter Hansen
Ronald Hansen
Karen Hanson
Kent Hanson
Lana Hanson
Valerie Hanson
Crystal Harbert
Mike Harbin
Jerry Harborth
Lance Harder
Peggie-Jean Harder
Darrel Hardes
David Hardes
Gisele Hardick
Chris Hardwick
Jackie Hardwick
Darrel Hardy
Jacob Hardy
Jennifer Hargis
David Hargrave
Olivette Hargraves
Allan Hargreaves
Chris Hargrove
Doug Hargrove
Susan Hargrove
Brad Hargues
Ashley Harkins
JD Harkrider
Allison Harling
Chuck Harling
Gordon Harmsen
Ted Harper
Wallace Harper
Lu Ann Harrington
Chris Harris
Dennis Harris
Joe Harris
John Harris
Karla Harris
Michael Harris
Royce Harris
Seyi Harris
Brian Harrison
Cubby Harrison
Shelly Harrison
David Hart
Robert Hart
Chris Hartley
Donald Hartman
David Hartnagel
Lynn Harton
Kara Harvey
Darrell Harwell
Kevin Harwi
Charles Harwood
Jo Hastings
Glenn Hatcher
Donna Hatchett
Florin Hategan
Jason Hatfield
Kyra Hatfield
Roy Hathcock
Brady Hatteberg
Michel Hattermann
Travis Hauger
Joe Havlik
Andy Hawkins
Harold Hawkins
Jeffrey Hawkins
Tony Hawkins
Michael Hawley
Cheryl Haworth
Colin Haworth
Easten Hawthorne
David Haxton
Robert Haxton
Prentis Hay
Amina Hayat
Erik Haycock
Clayton Hayden
Joe Hayden
Barbara Hayman
Chris Haynes
Dan Haynes
Robert Haynes
Darrell Hays
Mike Hazlett
Greg Head
Sherry Heald
George Heard
Danny Heatly
Jarrod Heaton
Brian Hebert
Brock Hebert
Clint Hebert
John Hebert
Rod Hebert
Russell Hebert
Glenn Hedgecoke
Brenda Hedgeland
Debi Hedges
Jessica Hefley
Vance Hefley
John Heg
Don Heid
Mike Heider
Russ Heidesch
Tracy Heim
Clint Hein
Brad Heinrichs
Mary Heins
Donald Heinsen
Jim Heinze
Bryan Helfenbaum
Tom Heller
Larry Helms
Brad Helton
Lon Helton
Austin Henderson
Fred Henderson
James Henderson
Laura Henderson
Ronetta Henderson
Sylves Henderson
Daniel Hengel

Cindy Henley
Brenda Henry
Beth Henson
Gregg Henson
Michael Henson
Denise Heppler-Balkum
Cathy Herman
Travis Herman
Vince Hermes
Ellen Herminghaus
Armando Hernandez
Bobby Hernandez
Cheryl Hernandez
Dorene Hernandez
Letty Hernandez
Lily Hernandez
Omar Hernandez
Robert Hernandez
Roger Hernandez
Jeanie Herndon
Bill Herold
Braddy Herold
Brett Herold
Zane Herring
Kyle Herrmann
Travis Herrmann
Karen Hertel
Vicki Hestand
John Hicks
Linda Hicks
Seann Hicks
Dan Higdon
Henry Higgins
Jason Higgins
Sissy Higgins
Neil Hightower
Kelly Hilburn
Billy Hill
Fielder Hill
Michelle Hill
Mindy Hill
Richard Hill
Phillip Hillian
John Hillier
Tricia Hillman
David Hills
Trevor Hilsendager
Keith Himel
Francois Hindlet
Cole Hinds
Michael Hiner
Ken Hinshaw
Lynn Hinsley
Steve Hippler
Bart Hiron
Greg Hirschman
Carl Hiscock
Nick Hise
Margaret Hitchcock
Paula Hix
Dean Hlad
Bryan Hnatiuk
William Hobbs
Charles Hodge
Phil Hodge
Cindi Hodges
Rodney Hodges
Myles Hodgson
Gary Hoehne
Bryan Hoeflein
Carl Hoelscher
Gary Hoesel
Bill Hoffman
Blake Hoffman
Robert Hoffman
Danny Hogan
Robert Hojnacki
Max Holdcraft
Joe Holden
Christopher Holder
Chad Holeman
Blaine Holitzki
David Holland
Christi Holley
Janice Holley
Brandon Holliman
Matt Hollingsworth
Doug Hollister
Scott Holloway
David Holm
Linda Holmberg
Maurie Holmen
Charlotte Holmes
Coyla Holmes
Steve Holmes
Tamara Holmes
Thom Holmes
Tom Holmes
Geoff Holmlund
Jerry Holsworth
Debbie Holt
Glen Holt
Theo Holt
Dwayne Holubowich
Derrick Honing
Ken Hooker
Susan Hooper
Tom Hooper
David Hope
Rick Hopkinson
Steve Hoppe
Clay Hoppers
Candace Hopson
Rose Horn
Jeff Horner
Lori Horner
Timothy Horner
Sandra Horning
Chuck Horsman
Gilbert Horton
Donna Hoskins
Angie Hoult
Aletha House
Tarsha House
Colleen Houston
Jay Houston
Mark Houston
Les Hoven
Jaren Howard

Kay Howard
Linda Howard
Mike Howard
Michael Howe
Fabian Hower
Karen Howland
Garnet Howlett
Brandon Hoye
Darrin Hrycak
Vern Hrycuik
Xue Fen Huang
Joe Hubbard
Joe Huber
Mike Huber
Ryan Huber
Christine Huculak
Abid Huda
Sharon Huddleston
Alicia Hudgens
Brett Hudson
Marvin Hudson
Michael Hudson
Robert Hudson
Ruthie Hudson
Santiago Huerta
Ray Huestis
James Huggard
Bonnie Hughes
Janice Hughes
John Hughes
Kathy Hughes
Patricia Hughes
Robert Hughes
Robert Hughes
Terence Hughes
Teo Huisman
Steve Hulke
Jason Hull
Leon Hulon
Anita Hulsey
Jeremy Humphers
Charanjeet Hunjan
Freddy Hunt
Regina Hunt
Tracy Hunt
Valarie Hunt
Andrew Hunter
Blake Hunter
Jeff Hunter
Melissa Hunter
Gary Huntsman
Nancy Hunziker
Ella Hurd
Robert Hurd
Avie Hutchinson
Carrol Hutchison
George Hutton
Mike Hutton
Pete Hutton
Timothy Huxley
Hoa Huynh
Rick Hyatt
Marcia Hyde
Keith Hymel
Laurie Hysell
Christine Ibrahim
Mariana Iftinca
Edward Imbery
James Innes
Janelle Innocent
Paul Iott
Roxana Irizarry
Jeremy Irwin
Maggie Irwin
Monika Isbach
Dan Isenhower
Brenda Ison
John Ivezic
Cathy Ivins
Hiroshi Iwabuchi
Lonnie Izard
Alan Jackson
Barry Jackson
Chance Jackson
Eileen Jackson
Garrett Jackson
George Jackson
Janet Jackson
Kenneth Jackson
Randy Jackson
Sally Jackson
Travis Jackson
William Jackson
Gregg Jacob
Benson Jacobs
Rick Jacobsen
Deborah Jacobson
Keith Jagord
Rodney Jakubowski
Kenneth James
Randall James
Bret Jameson
Debra Jameson
Joann Jamieson
Rick Janigo
Raquel Janoe
Jamie Janota
Tom Jantz
Michael Janz
Leroy Jardie
Robert Jardine
Michelle Jarrett
Darrell Jarvis
Roland Jaso
Brian Jeffrey
Wendy Jenish
Kathryn Jenkins
Kyle Jenkins
Ronald Jenkins
Donald Jennings
Kim Jensen
Margaret Jensen
Ryan Jensen
Nick Jenson
Dee Jerome
Pierre Jobin
Billy Johnson
Billy Johnson
Christopher Johnson

Constance Johnson
Daniel Johnson
David Johnson
Jesse Johnson
Judy Lynn Johnson
Marcel Johnson
Mike Johnson
Monica Johnson
Patti Johnson
Patty Johnson
Robert Johnson
Tip Johnson
Tommy Johnson
Vivian Johnson
Dennis Johnston
Duane Johnston
Everette Johnston
Joe Johnston
Kimberly Johnston
Haywood Joiner
Brad Jolley
Cassey Jones
Cole Jones
Craig Jones
Cynthia Jones
Dan Jones
David Jones
Desmond Jones
Donna Jones
Freddie Jones
Fredrick Jones
J. Phil Jones
Jeremiah Jones
Jervis Jones
John Jones
Katie Jones
Keri Jones
Kevin Jones
Mike Jones
Mike Jones
Norman Jones
Paul Jones
Randy Jones
Samantha Jones
Scott Jones
Steven Jones
Tim Jones
Traci Jones
Duskin Jordan
Gregory Jordan
Robert Jordan
Justin Jorns
Greg Joss
Florence Josue
Carolyn Joy
William Joy
Chelsea Jozwiak
Jose Juarez
Steven Judd
Rosemary Junell
Dana Jurick
John Juska
John Kachelmeyer
Kevin Kajorinne
Marilyn Kalanchey
Murray Kalita
Christine Kalivoda
Justin Kallenberger
Ray Kallenberger
Patrick Kamann
Zahir Kanji
John Kanouff
Curtis Kantenberger
Rikki Kanuit
Melanie Kapp
Ibrahim Karaibrahimovic
Murray Karbonik
David Karg
Misty Kasdorf
James Kassiones
Russ Kassner
Roger Kearnes
Fikre Kebede
Kossila Kechemir
Don Keefer
Mary Keele
Alice Keelin
Judith Keen
Jon Keenze
Gary Keeping
Harold Keessar
Peter Kellar
Greg Kelleher
Fay Keller
Kimberly Keller
Jeff Kelley
Lacy Kelley
Lisa Kelley
Fred Kellow
Debbie Kelly
Paul Kemp
Amanda Kendall-Seel
Malinda Kendrick
Michael Kendrick
Robert Kennard
Breanne Kennedy
Dan Kennedy
Gary Kennedy
Kristin Kennedy
Terry Kennedy
Linda Kenney
Gregory Kent
Darren Keough
Kelly Kerby
Philip Kerig
Jack Kerkhof
Michelle Kerman
Shannon Kern
Bill Kerr
Daniel Kerr
Debbie Kerr
Jo Ann Kerran
Sherrill Kerstens
Dheal Ketchum
Kim Ketchum
Aaron Ketter
Yasin Khan
Sandeep Khurana
Monica Kibler

Aaron Kidd
Tracy Kidd
Robert Kiesewetter
Jeff Kiester
Robert Killeleagh
Patty Killman
Klaholt Kimker
Bev Kinch
Elizabeth Kindle
Carolyn King
Reginald King
Kelly Kingsmith
Mike Kinman
Bobbie-Jo Kirby
Scharine Kirchoff
Pat Kirkendoll
Joyce Kirtley
Hal Kissner
Steven Kistler
Jennifer Kitchell
Susannah Kitchens
Mark Kitsmiller
Barbra Kizmann
David Klaassen
Cheryl Klein
Roger Klein
Rusty Klein
Steve Klein
Adam Kline
Ed Klingbell
Melissa Klinger
Stephen Knapp
Dale Knepper
Cynthia Knight
David Knight
Earl Knight
Joanne Knight
Kimberly Knight
Randy Knight
Roy Knight
Skipper Knight
Bruce Knopf
Dale Knox
James Knox
Clem Kobelsky
Bradley Kodama
Janna Koehn
David Koelsch
Burton Koenig
Kyle Koerner
Gary Kofoed
Michael Kohl
Carla Kolody
Jennifer Koloen
Kevin Koon
John Koop
Chris Korczewski
John Korzenoski
Jason Kosanovich
Ron Kosheiff
Lisa Koss
Diane Kossman
James Kothe
L.J. Kotlarich
Richard Kovach
Raymond Kowal
Norman Kowalchuk
Jana Kowals
Michael Kozak
Erin Kozakiewicz
Beverley Kozdrowski
Tony Kozyra
Kathleen Krahulic
Mark Kramer
Katie Kregger
Darryl Kreutziger
Jason Krobot
Ana Krueger
Steve Krueger
Gary Kruk
Kevin Krynowsky
Jon Krystinik
Alischa Krystyniak
Joe Kuehler
Steve Kuhn
Nathan Kuhnert
Pam Kuhr
Gary Kump
Gregory Kuran
Susan Kurczaba
Melanie Kushneryk
Erik Kvale
Connie Kwan
Virgil Kwiatkowski
Evelyn Kyes
John Kyes
William La Fleur
Marc LaBerge
August Labouncan
Denis Labrecque
Monte Lackey
Randy Lackey
Mike Lacroix
Tom Laffery
Steve Lafollette
Caroline Lafond
Aleksander Lajzer
Celia Lam
Chuck Lamar
Holly Lamb
Clinton Lambert
Jenni Lambert
Kenneth Lamers
Todd Laminski
Walter Lamle
Cory Lancaster
Brian Lanctot
Tammy Landis
Dean Landry
Patrick Landry
Stacey Landry
Bryan Lane
Emily Lane
Frank Lane
Darryl Lang
Casey Lange
Kerry Lange
Tim Langenberg
Mike Langfield

Craig Langford
Lynne Langston
Dusty Lantz
Mike Lantz
Debra Lanz
Pete Lapeyrouse
Ann LaPrade
Christopher Laqua
Joe Lara
Jerry Larance
Alisha Largo
Terry Larko
Lisa Larsen
Rhonda Larsen
Doug Larson
Elizabeth Larson
Glenn Larson
Gregg Larson
Robert Larson
Cindy Lasher
Darren Lasley
Cody Latham
Asif Latif
Glenn Latimer
Lynn Latiolais
Chris Latkiewicz
Brian Laughlin
Robert Lauze
Cheryl Lavarnway
Joe Lawlis
Clint Lawrence
Perry Lawrence
Nancy Lawshae
Whitney Lawson
Nicole Lawton
Sheila Lazzari
Vu Le
Corey Lea
Pamela Lea
Rachel Lea
Lou Leake
Jim Leathers
Heath Lebeouf
Aaron LeBlanc
Raymond Leblanc
Cathy Lebsack
Barbara LeClaire
Al Ledbetter
Angelo Ledda
Charles Lee
Chris Lee
Danny Lee
Didra Lee
Jason Lee
Jill Lee
Joseph Lee
Kevin Lee
Licia Lee
Mary Lee
Shonda Lee
Ronnye Leech
Alesha Leemaster
Kristi Leeper
Beatrice Leer
Ian Lees
Lynda Leeth
Stephen Lefebvre
Karen Lefevre
Margaret Legge
Brad Leggett
Phil Leibel
Allen Lejeune
Darell Lejeune
Tommy Lejeune
David Leland
Teresa Lemieux
Ronald Lemoine
Amber LeMond
John Lenhart
Karen Lennox
Louis Lentz
Ceci Leonard
Harry Leonard
Kyle Leonard
Chris Leong
Cathy Leriger
Cody Leroux
Dan Leslie
Robert Leslie
Alarice Letarte
Abby Letsey
Andre Letourneau
Julie Leung
Thomson Leung
Warren Leung
Cheryl Levesque
Michael Levesque
Todd Levesque
Bob Lewis
Casey Lewis
David Lewis
Donnell Lewis
Dwayne Lewis
Glenn Lewis
Larry Lewis
Merle Lewis
Rebecca Lewis
Brian Lewitski
Terry Leyenberger
David Leyland
Shanshan Li
Ying Li
Nathan Liegman
Charles Lilly
Ted Lilly
David Lin
Jia-Wen Lin
Thomas Lin
Wesley Lincoln
Benny Lindley
David Lindsay
Tom Linehan
Kelsey Linnell
Don Linscomb
Traci Linscomb
Darryl Linton
Jim Linville
Leslie Linville
Mark Lisbeth

A. Gregory Little
Debbie Little
Gary Little
Gordon Little
Sara Little Jim
Peter Liu
Robert Lively
W. Andrew Livingston
Henry Livingstone
William Livingstone
Jaimelyn Liwag
Tony Loch
Brian Lock
Woody Lockhart
Janell Lodge
Kent Loeffler
Derek Lofstrom
Diane Lofstrom
Debbie Logelin
Rich Lohner
Dave London
Steve London
David Loney
Dianna Long
Karen Long
Yvonne Long-Starling
Sandy Lookabaugh
Michael LoParco
Pamela Lopas
Ty Lopes
Nicole Lopez
Don Lorson
Grant Los
Charles Lott
Erik Lottermoser
Amy Lou
William Louder
Albert Louie
Randy Louviere
Russell Louviere
Julia Love
Renee Love
Nichole Lovey
Peter Lovie
Lanny Low
Dan Lowe
Ryan Lowe
Stephen Lowe
Trey Lowe
Vance Lowes
Leonard Loyek
Bernie Lucas
Brenda Lucy
Richard Luedecke
Terry Luedke
John Luff
Stanley Lui
Ana Luistro
Paul Luker
Andy Lum
Terri Luman
Helge Lund
Chuck Lundeen
Christina Lundgren
Corrine Lung
Dick Lunsford
Tony Luoma
Devin Luper
Brad Lusk
Carol Lustig
Perry Lutz
Robert Lux
Georgia Lykidis
Justin Lynch
Francis Lyne
Marianne Lynn
Diane Lynnes
Leeanne Lyon
Mark Lyon
Mike Lyon
Victor Lyons
Brenda Lytle
Dominic Ma
Tracy Ma
Corey MacDonald
Elaine MacDonald
James MacDonald
May-Lee MacDonald
Penny MacDonald
Duane Macgowan
Scott MacGregor
David Machuk
Tracy Macijuk
Deanne Mack
Jonah Mackay
Jerry Mackey
Paxton Mackey
Anne MacLean
Elizabeth MacLean
Grace MacLean
Michael MacLean
Robyn MacLean
Todd MacLean
Hugh MacLennan
Warren MacPhail
W. Reigh MacPherson
Lee Madsen
Lee Maes
Olga Magas
Lindsay Magdaleno
Brenda Magee
Jan Maggard
Raymond Maggiore
Herb Magley
Catherine Magnan
Kevin Maguire
Michael Maguire
Kyla Mah
Lilac Mah
Mimi Mah
Virgil Maier
Magella Mailloux
Michael Makin
Jay Malanowich
Linda Malaske
Zack Maley
Kristen Mallory
Nick Mallory
Jillayne Malo

Phyllis Maloney
Tara Manbodh
Peter Manchak
Ben Manek
Lois Manes
Derold Maney
Tracy Manford
Paul Mangum
Gary Mann
Kurt Mann
Tommy Mann
Craig Manning
Judy Mansfield
John Manuel
Linda Marantica
Burgess Marcantel
Donna Marceaux
Garry March
Wendy March
Andrea Marchand
Raymond Marchand
Steven Marcks
Robin Marcotte
Alan Marcum
Roy Marcy
Stephanie Mark
Carol Markell
Paul Marker
Ross Markowski
David Marks
Kenny Markve
Deona Marlar
John Marler
Connie Marlow
Kimberly Marquis
Stuart Marriott
Kevan Marsh
Travis Marsh
Grant Marshall
Marc Marshall
Sharon Marshall
Vernon Marshall
Pat Martell
Bruce Martin
Dennis Martin
Donnie Martin
Herb Martin
Jack Martin
Jeremy Martin
June Martin
Lavinia Martin
Maria Martin
Mark Martin
Rick Martin
Robbin Martin
Scott Martin
Scott Martin
Steve Martin
Gerry Martineau
Sandra Martineau
Benny Martinez
Maria Martinez
Rudy Martinez
Ken Marx
Jorge Marzetti
Jim Mashaw
Chris Maskowitz
Steve Masri
Rocky Massengale
Carol Massey
Garnett Massey
Connie Mata
Mark Matalik
Kenneth Matchett
Jerry Mathews
James Matlock
Fred Matt
Ray Matt
Stephen Matthews
Randall Matychuk
Paul Mauger
Andre Maurier
Randy Maxey
Mary Maxim
Donald Maxwell
Kelly May
Peggy May
Cynthia Maya
Don Mayberry
Allan Mayder
Frederick Mayer
Rob Mayeux
Glen Maynard
Kevin Maynard
Gary Mays
Mike Mays
Donna Mazurek
Jerry Mazurek
Mark Mazzolini
Kelly McAdams
Robert McAdams
Perry McAlister
C. Rodney McArthur
Kevin McAulay
Marylin McAulay
Stanton McAvoy
Nadine McCabe
Brent McCaffrey
Don McCall
Jim McCallum
Gwen McCarty
Kathy McCarty
John McCaskill
Pat McCelvey
Bruce McClain
Laurie McClain
Kyle McClellan
Gordon McClelland
Tiffany McClendon
Craig McCollough
Brian McComas
Bernard McCormick
Randy McCormick
Randi McCorquodale
Debra McCoy
Lesley McCoy
Willie McCoy
Will McCrocklin
Brian McCullagh

Vanetta McCullough
Heather McCutcheon
Carol McDaniel
Derrick McDaniel
Mark McDaniel
Cameron McDonald
Charles McDonald
David McDonald
Debra McDonald
Jeff McDonald
Jenelle McDonald
Pam McDougall
Alicia McDuffie
Robbie McEachnie
Kelly McElhaney
Irene McEvoy
Jody McEwen
Lee McFarland
Dean McGarry
Maggie McGehee
Brandon McGinley
Todd McGlauchlin
Helena McGough
Steve McGough
Colin McGovern
Ernie McGowen
Gregory McGowen
Roy McGowen
James McGregor
Scott McGregor
Dwain McGuire
Lynn McGuire
Michelle McGuire
Little McGullion
David McHarg
Keith McInroe
Gary McIntyre
Louise McIntyre
Terry McIver
Neil McKeachnie
Verna McKean
Danielle McKee
Kyle McKee
Vance McKee
Dan McKeever
Kathryne McKeever
Bobo McKenzie
Nicole McKenzie
Kenneth McKibben
Curt McKinney
Michael McKinney
Scott McKinney
Shaleen McKinney
Steven McLaughlin
Matthew McLean
W. Jeffrey McLean
Donald McLeod
Travis McLeod
Mike McMahan
Billy McMillan
Jeanie McMillan
Mark McMillan
Rodney McNabb
Philip McNeil
Kyle McNeill
Jim McPhee
Danny McPhetridge
Craig McPhie
Robbie McPike
Karen McQuiggan
Tim McTaggart
Jeff McVay
Ron McWhorter
Glen McWilliams
Niles McWilliams
Thad Meador
Michael Means
Fran Mears
Sandra Meche
Tony Medley
Barbara Meekins
Judith Megli
Balu Meharwade
Joseph Mehring
Betty Meixner
Arturo Mejorado
Dave Melancon
Harry Mellafont
Anna Melo
J. Dennis Meloche
Teresa Mendiaz
Jorge Mendoza
Gulanar Merali
Katie Merchant
Monty Merecka
Phillip Meredith
Maryanne Merlock
Charlene Merrill
Gerald Meshen
Kathryn Mesi
Frank Messa
Gregory Messner
Talbot Mestayer
Robert Metcalf
Tina Metting
John Meyer
Craig Meyer
Ellen Meyer
Travis Meyers
Meagen Michael
Sean Michalski
Mark Michell
Andrew Mickleborough
Mike Middleton
Brenda Milam
Cliff Milam
Phil Milam
Andrea Miles
Bill Miley
Thorin Miley
Betty Millen
Brad Miller
Casey Miller
Donna Miller
Fred Miller
Gary Miller
James Miller
Janelle Miller
Kurt Miller

Kyle Miller
Larry Miller
Linda Miller
Melissa Miller
Michael Miller
Patrick Miller
Reginald Miller
Ryan Miller
Yamoria Miller
Don Millett
Kathy Millett
Dixon Millican
Peter Millman
David Mills
Don Mills
Michel Mills
Randy Mills
Jason Milner
Dane Milton
Jose Minas
Karlee Mink
Johnny Minton
Chip Minty
Travis Miron
Elliott Miska
Dewayne Misner
Rebecca Missman
Gregg Mitchell
Lisa Mitchell
Randy Mitchell
Rick Mitchell
Stacey Mitchell
Trudy Mitchell
Jerry Mitchum
Johnny Mixon
Michael Mlcak
Clarence Moberly
Andy Mobley
Todd Moehlenbrock
Bobby Mogford
Cecilia Mo-Irving
Bryan Molaison
Thomas Molaison
Delia Molina
Robert Mollison
Gwen Monarch
Doug Monk
Emma Montgomery
Gerald Montgomery
MariLynn Montgomery
Frank Monthey
Ralph Montoya
Ida Moody
Mark Moody
Marian Moon
Dan Mooney
Steve Mooney
Brent Moore
Brian Moore
David Moore
Donna Moore
Douglas Moore
Josh Moore
Marc Moore
Patrick Moore
Shelley Moore
Travis Moore
Tom Moores
Lutie Mora
Danny Morales
Oscar Morales
Ray Morales
Ruby Moran
Carla Morasch
Roy Morehead
Vincent Moreland
Steven Morency
Colleen Moretti
Josh Morgan
Rory Morgan
Todd Morgan
Warren Morgan
Brenda Morgensen
Nicole Morissette
R. Peter Morissette
Rod Moroz
Brian Morris
David Morris
Grant Morris
Phyliss Morris
Debbie Morrison
Greg Morrison
Rodney Morrison
Tracy Morrison
Charity Morrisseau
Frederick Morrissey
Dick Morrow
Darrell Mosby
Fausto Mosca
Robert Moser
Anne Moses
Robyn Mosk
Mike Moss
Neil Moss
Rochelle Mote
Keith Mott
Frank Motycka
Lorraine Mounkes
Michael Mouton
Kelly Mower
Charles Mowry
Christina Moy
Benjamin Moye
Oscar Mueller
Meg Muhlinghause
George Mullen
Steve Mullen
Trent Mullen
Marius Muller
Justin Mullinax
Jeremy Mullins
Victor Munding
Pete Mundy
Amanda Muniz
Fabian Munos
Sophia Munoz-Guzman
Aurea Munro
Kim Munro
Michael Munsey

George Munzing
Jeff Murphree
Barbara Murphy
Bob Murphy
Ed Murphy
Kenneth Murphy
Thomas Murphy
Tom Murphy
Jordan Murray
Lloyd Murray
Patti Murray
Paul Murray
Shawn Murray
Tyler Murray
David Murrell
Richard Myal
David Myers
James Myers
David Naas
John Nabors
Gary Nagorka
Rick Nagy
Ami Naik
Ethan Nall
Larry Nantz
Gary Nash
Jeff Nation
Mike Naus
Tom Nay
Shiraz Nazerali
Francis Nazzal
Traian Neacsu
Randy Neal
Rand Nedved
Keith Needham
Tom Negenman
Jamie Neibauer
Debby Nelson
Donnie Nelson
Kelly Nelson
Lori Nelson
Martin Nelson
Sharlene Nelson
Tom Nelson
Rosie Nelson-Taylor
Candy Nesom
Scot Nesom
Kristian Nespor
Jimmy Netowastanum
Paul Neubauer
Sidney Neudorf
Kim Neugebauer
Darla Neundorf
Jack Neuner
Jon Newell
Kelley Newkirk
Nancy Newman
John Newton
Nick Newton
Benny Ng
Daniel Ng
Esther Ng
Michael Ng
Alex Nguyen
Danh Nguyen
John Nguyen
Phuong Nguyen
Tom Nguyen
Tony Nguyen
Kenneth Nibbelink
Vickie Nicholas
George Nichols
Larry Nichols
Nick Nichols
Paul Nicholson
Frances Nickel
Mike Nicol
Patric Nicol
Michael Nicolaides
Darlene Nicols
Darcy Niedermaier
Marilyn Nielsen
Tim Nielsen
Mike Nivens
Toby Nivens
Jessie Nix
Ken Nixon
Brian Noland
Taylor Noland
Danny Nolen
Blair Nolin
David Nollsch
Ernie Nonog
Shannon Nordstrom
Bradley Nore
Janna Norman
Mike Norris
Carol Norton
Glenn Norwood
Tamara Novogrudsky
Rudy Nowak
Danielle Nusbaum
Jeff Nutter
Dale Nyegaard
William Nystrom
Jason Oakley
Mark Oates
Don OBeirne
Eugene O'Brien
William O'Brien
Dave O'Bright
Karen OConnell
Steve O'Connell
Maureen O'Connor-Horvat
David Oczkowski
Clay Oden
Ernest Oden
Karla ODonnell
Mike O'Donnell
Heather Offet
Daniel Offutt
Lana Offutt
Scott Ogier
Lee Ogle
Tim Ogle
Christopher Ogston
Michael Ohara
Calvin Oldfield
Peter Olesen

Charles Oliver
Corby Oliver
Dwane Oliver
Jeff Oliver
Tamara Ollenberg
Allan Ollenberger
Sean Olmstead
Grant Olsen
James Olson
Adam Olszewski
Wanda Olszewski
Tunde Oluokun
John Ondrey
Art Oneal
Patrick ONeill
Sandra Onia
Scott Opdyke
Mark Orchard
Ryan Orcutt
Trevor Ord
Dennis Ortego
Andrea Ortiz
Marcos Ortiz
Jay Ortner
Melissa Osborne
Robert Osbourn
Cindy Osina
Dale Oslanski
Brooke Osler
Donald Oszust
Jason Otto
Ben Ouellet
Jason Ouellet
Jason Overcash
Brian Overman
Amanda Owen
Ben Owen
Eddie Owen
Greg Owen
James Owen
Dave Owens
Stephanie Owens
Steve Owens
Tracee Owens
Whitney Oxley
Paul Ozar
Kenny Pace
Cynthia Paige
Brad Pakkala
Mona Pal
Chris Palazzo
Katherine Pallister
Courtney Palmer
Douglas Palmer
Michael Palmer
Shaun Palmer
Bianca Palosanu
Norman Pals
Chris Pan
Nicole Paniel
Amy Pannell
Tom Pape
James Pappas
Bob Paradiso
Sheila Pardo
Gloria Pardo-Contreras
Elsa Parece
Hector Parent
Kim Parent
Robert Parish
Becky Parker
Carolynn Parker
David Parker
Don Parker
Linda Parker
Randy Parker
Calvin Parks
Fred Parks
Jeff Parks
Michele Parks
Walter Parlange
Dennis Paron
Lori Parr
George Parra
Mariela Parra
Paula Parra
Ted Parrish
Spencer Partridge
Thomas Pasco
Sonal Patel
Placido Patriana
David Patterson
Donald Patterson
Martyn Patterson
Carol Patteson
Hardy Patton
Jeff Patton
Mark Patton
Sherri Patton
Wesley Paugh
Joe Paul
Tim Paul
Mark Paull
Meghan Paulson
Regina Paura
Rob Pawlik
Wesley Pawlik
John Pawluski
Ben Payne
Dal Payne
Fred Payne
Johnny Payne
Jonathan Payne
Karen Payne
Micheal Payne
Ray Payne
David Pearce
John Pearce
Joyce Pearn
Brandon Pearson
Edward Pearson
Janet Pearson
Kathy Pearson
Ross Pearson
Brandon Peck
Bridger Peck
Heather Peck
Finn Pedersen
Dwayne Pederson

Dave Peet
Jorge Peinado
Althemus Pellerin
Jean Pelletier
Neil Pelletier
April Pels
Cindy Pemberton
Al Pena
Amanda Pendegrass
Tim Pendleton
Bill Penhall
Barbara Penman
Holly Penner
Cathy Pennington
Matthew Pennington
Shelby Pennington
David Pennybaker
Shelagh Penson
Kevin Peppler
Denise Percival
Wagner Peres
Carlos Perez
Elisa Perez
John Perez
Christine Perkins
Deanna Perkins
Guy Perkins
Kerry Perkins
Richard Perkins
Michael Perlette
Daniel Perna
Deborah Perrault
Debbie Perrin
Dusty Perry
Kathy Perry
Robert Pessia
Aida Peters
Gerald Peters
Gord Peters
Pam Peters
Casey Petersen
Paula Petersen
Charles Peterson
Chuck Peterson
Gerald Peterson
Kyle Peterson
Terry Peterson
Kamberly Petete
Anthony Petkovich
Rob Petrone
Shannon Petrusawich
Allen Petry
Clayton Petry
Patrick Petry
Barbara Pettigrew
Bill Pettitt
David Pettus
Matthew Pettyjohn
Chip Phillips
Marvin Phillips
Matt Phillips
Russell Phillips
Sherry Phillips
Tyler Phillips
Jimmy Phipps
Lily Phung
Judy Pickering
Travis Pickering
Mark Pickup
Michal Picquet
Lawrence Pidkowa
Penny Piekarski
David Pierce
Duane Pierce
Eddie Pierce
Jimmy Pierce
Joe Pierrottie
Jerry Pierson
Leslie Pietron
Charlie Pike
Kimberly Pike
Charlie Piland
Norman Pimm
Cathy Pineda
Jerri Pinel
Susan Pinkney
Olivia Pinto
Risa Pippin
Peter Pisz
Robert Pitt
Jack Pittman
Vince Pitts
Ryan Pivonka
Merle Plamondon
Glen Plaska
Mary Platt
Charlotte Plombin
Earl Plumb
Brandi Plumlee
John Podhaisky
Ray Podoba
Albert Poetker
David Poirier
Debbie Poirier
Danny Polak
Paul Poley
Kimberly Polhemus
Mike Polhemus
Terry Pollard
Tommy Polly
Jeffery Polsfut
Eva Polyak
Marilyn Pomeroy
Marvinette Ponder
Richard Pontello
Darris Ponthieux
Kelly Poon
Lucas Popinski
Ron Poppenga
Al Poprik
Charles Portelance
Justin Porter
Robin Porter
Lenny Post
Dan Postler
Randi Poteet
Greg Potter
Rory Potter
Tracy Potter

resource

We have built our company on a solid foundation of core beliefs and values that have shaped our past and map our future. From this foundation, we draw upon precious resources such as innovation, teamwork, integrity and perseverance. More critical than the energy resources we produce are the convictions that guide us as we work.

In preparing this annual report, we talked with a cross section of Devon employees and stakeholders outside the company about Devon's character and how we conduct our business. In the following pages, along with community, environmental and operational highlights, these individuals share their unique perspectives.

“They understand that shareholder value and the bottom line are enhanced by **investing** in the community and especially by investing in the **next generation**.”

DAVID BOREN
PRESIDENT, UNIVERSITY OF OKLAHOMA
NORMAN, OKLAHOMA

“As president of the University of Oklahoma, my role is to help build an outstanding university, and the leadership at Devon shares my mission.

“It is not a coincidence that strong and productive companies are most often located in strong and flourishing communities. The two go together and Devon understands that. They understand that shareholder value and the bottom line are enhanced by investing in the community and especially by investing in the next generation.

“Devon has invested in new facilities, scholarships, internships and research programs at OU. Their contributions are helping us produce a pool of outstanding graduates that Devon can draw from to maintain its talented workforce.

“Devon has succeeded as a company and is becoming an even greater company because its leaders have the vision to understand that their business interests coincide with the public interest. Devon is not only a corporate partner for OU, its leadership and its values serve as a model and an inspirational guide for our students.”

"Although our Devon tutors can only spend a short time at our school each week, their faithful dedication has made a significant impact on the lives of our students."

TRINA STANBERRY
COMMUNITIES IN SCHOOLS PROJECT MANAGER
THOMPSON ELEMENTARY SCHOOL
HOUSTON, TEXAS

"While Devon provides funding for some of our school activities, the most important gift they give us is their time. Our students light up when their tutors arrive and it's often the highlight of their day."

CHUCK TOMPKINS
PRINCIPAL, MARK TWAIN ELEMENTARY SCHOOL
OKLAHOMA CITY,
OKLAHOMA

"Devon's commitment to innovation means a lot to me as an employee. Our company is always looking at better ways to do our business, which helps me and my staff better monitor our business and accomplish more."

MANDY WRIGHT
DEVON SUPERVISOR, ACCOUNTING OPERATIONS
OKLAHOMA CITY, OKLAHOMA

" When my community has a need, we can always count on Devon to get involved. Devon has been in our community for several years, contributing to public education, youth recreation, senior support programs and a variety of other community service efforts."

WENDY TREMBLAY
ABORIGINAL COMMITTEE MEMBER OF THE
CONKLIN MÉTIS LOCAL #193
CONKLIN, ALBERTA

"In the area of community relations, Devon sets an excellent example for others to follow. The company supports public education, its employees are active in the community and it supports public safety programs."

ROY EATON
PUBLISHER, WISE COUNTY MESSENGER
DECATUR, TEXAS

"Devon's like a big family, and that makes it a lot easier for everyone to do their jobs. The friendly environment is why I enjoy coming to work each day, and I think it makes people want to do their best for the company."

REAH TORRES
DEVON RECEPTIONIST
HOUSTON, TEXAS

Community Outreach

Commitment of Resources

To succeed in the field, energy companies must have support from the communities that surround their operations. We consider ourselves part of the towns, cities and rural areas where we explore for and produce oil and natural gas. We live there, work there, play there, worship there and send our children to school there.

Our business operations depend on a solid footing that can only come from stable communities. That is why we work to build relationships and donate financial resources to civic organizations, schools, law enforcement agencies, fire departments and youth programs.

We are grateful to have opportunities to contribute to programs and services that enhance the quality of life for our employees and their neighbors. By investing in the future of our communities, we are investing in the future of Devon.

Ambassadors Strengthen Community Bonds

Serving on school boards, donating equipment to emergency responders and speaking to students about oilfield safety are fundamental to our business. Devon's employees are dedicated to the business of economically finding and producing the oil and natural gas that maintains Devon's position as one of the industry's top energy producers. But that is only part of our role in the communities where we do business. We also spend time as volunteer teachers, little league coaches and city council members.

Working within our communities is essential to our success as a company, and it is an integral part of our corporate culture. By supporting the communities where we live and work, we enhance the quality of life for ourselves and our neighbors. Devon's ambassador program is a key component of its commitment to community outreach.

The ambassador program succeeds because of our employees. Devon ambassadors are prominent members of community organizations, available to answer questions about our operations and to open lines of communication with all of our stakeholders.

For Bill Skelton, being a Devon ambassador in Riverton, Wyoming, requires owning a "good pair of boots." As an ambassador, Bill seeks opportunities to make a positive impact in his community. He volunteers to help local law enforcement with search and rescue operations—saving accident victims and searching for lost children.

Thousands of Devon employee volunteers build relationships with landowners, civic leaders and regulators. These relationships help us work together, whether we are addressing a community need or responding to an emergency in the field. As they serve their communities, these volunteers are strengthening bonds and building partnerships.

Mike Naus from Devon's Gillette office talks with students about wildlife and the environment during the Wyoming Hunting and Fishing Heritage Expo in 2006.

Devon helped re-equip firefighters in Vermilion Parish, Louisiana, following the devastating Gulf Coast hurricanes of 2005.

Devon Continues Support for Gulf Coast Recovery

More than a year after hurricanes Katrina and Rita pummeled the Gulf Coast, Devon has not forgotten the people that were impacted by the devastation. As families return to places they once called home, many local schools, social service organizations and emergency responders remain without the supplies and equipment they need to serve their communities.

Immediately following the hurricanes, Devon responded with contributions and volunteers to help victims begin the healing process. Devon's $2 million contribution to relief efforts aided restoration initiatives along the Louisiana and Texas coastlines. But our relief effort has not stopped there. Devon continues to make significant contributions to the restoration process by targeting needs that are not covered by government agencies and insurance programs.

For example, we have worked with local schools in Louisiana to identify ways we can help students and faculty recover from the losses their facilities sustained in the storms. As a result, we have purchased everything from school supplies to furniture, computer equipment and even rain ponchos to help protect students as they walk between portable classrooms. At Erath High School in Louisiana, we funded a new floor for the gymnasium, which also serves as a community gathering place and recreation center.

The storms also consumed vital equipment used by firefighters in Vermilion Parish Louisiana. Devon contributed $180,000 to ensure that these first responders are adequately equipped to serve their communities. Devon has also contributed to organizations that provide post-trauma counseling, clothing and tutors for evacuated students.

In addition to corporate funding, many of our employees continue to make personal donations to assist hurricane victims. In December 2006, Devon employees in Louisiana made the holidays a little brighter by purchasing clothing and toys for the children of families still struggling with the recovery.

While the hurricanes have long been over, the devastation they caused continues to affect the lives of many in the coastal communities where we live and work. As an energy producer, we depend on our communities to create a solid foundation for our business and our employees. Because we have been graced by the support of many communities that shared in the disastrous effects of Katrina and Rita in 2005, we share the responsibility for picking up the pieces the storms left behind.

"I see the respect Devon gets from service companies, the Bureau of Land Management and from people who live in the town of Baggs. As a petroleum engineer, working for a company with a good reputation makes my job easier. People are easier to talk to and work with because they trust Devon."

MEGAN STARR
DEVON OPERATIONS ENGINEER
BAGGS, WYOMING

"There are certain companies that have established themselves as leaders. Through their conduct and their participation they are able to shape the direction of the industry. Devon is one of those companies."

MARC SMITH
EXECUTIVE DIRECTOR
INDEPENDENT PETROLEUM
ASSOCIATION OF
MOUNTAIN STATES
DENVER, COLORADO

"Credibility is essential to be effective in Washington. Devon exemplifies the new image of an independent producer. It's big enough to participate in any project, but its roots are solidly in America."

LEE FULLER
VICE PRESIDENT, GOVERNMENT RELATIONS
INDEPENDENT PETROLEUM
ASSOCIATION OF AMERICA
WASHINGTON, D.C.

"The best way to handle a problem is to address it, not back away from it. Devon is the kind of company that works with me. They want to help people and make things work. It's the mark of an honest company. If there's a mistake, the honest company will work it out. If they're dishonest, they'll never resolve it."

R.C. MCFALL
COUNTY COMMISSIONER
JOHNSON COUNTY, TEXAS

"Our environmental, health and safety philosophy started with a **commitment** our management was willing to make, and now it is one of the things that sets us apart from our peers."

DARREN SMITH
DEVON ENVIRONMENTAL SCIENTIST
OKLAHOMA CITY, OKLAHOMA

"Devon has adopted an environmental, health and safety philosophy that calls on us to conduct our business ethically and lawfully. It also requires us to seek ways to operate in a manner that is safe and compatible with the environment as well as with the communities that surround our operations.

"The philosophy is more than a priority. It's part of our system of values, which is important, because priorities can change, but values are concrete.

"Our philosophy is a top-down commitment, and that's the best part. We are all held accountable for our EHS performance. As a supervisor in our environmental group, that makes my job a lot easier.

"People are welcome to suggest new ideas that could make our operations more efficient, better for the environment and friendlier to our neighbors. Great ideas are coming in from the field because people are encouraged to think that way. As a result, our environmental programs are among the best in the industry.

"Our environmental, health and safety philosophy started with a commitment our management was willing to make, and now it is one of the things that sets us apart from our peers."

Environmental Partnerships

A Resourceful Approach to Conservation

Devon is committed to the preservation of our natural environment, especially air and water. Our commitment has resulted in successful initiatives companywide that have established Devon as an industry leader in environmental responsibility.

We are gratified by our progress, and we are even more excited about our future as we continue a course of innovation in the areas of emissions reduction and water conservation. While Devon's greenhouse gas emissions reduction programs are already in place, our accomplishments in 2006 created a new platform for greater reductions in the future. In addition to these achievements, our water conservation programs continue to expand with new technology that could eventually be applied to production operations companywide.

Conservation is our goal as a good neighbor and is consistent with our objective to continue to be a top performer in the highly competitive energy industry. By keeping more natural gas in the pipeline and reducing water usage, we can increase production and cut operating costs. That is not only good for the environment, it is good for our bottom line.

Technology Drives Emissions Reduction Effort

Between 1996 and 2005, Devon has accounted for emission reductions of more than 15 million tons of carbon dioxide equivalent as reported through voluntary government programs in the United States and Canada. We have reduced emissions through the use of new technology, and we have found innovative new approaches to our well completion and production methods. For example, Devon has initiated a program to replace old pneumatic devices with the latest technology designed to substantially reduce methane emissions. Devon is replacing hundreds of these "old technology" devices at production sites companywide. Each replacement accounts for an emission reduction of 100 tons of carbon dioxide equivalent each year. That is like taking 20 cars off the road.

By capturing natural gas normally lost in the production process, we have been able to increase the volume of gas available for sale. In 2005, we were able to retain six billion cubic feet of natural gas that would have been lost to the atmosphere using traditional practices. With an economic benefit of more than $43 million, doing what makes sense for the environment also enhances our profitability.

Since 1999, Devon has earned recognition by government agencies for being an industry leader in emissions reduction and reporting. In the United States, the Environmental Protection Agency has honored Devon repeatedly for its performance and for its advocacy. In Canada, Devon's efforts have earned the company elite status from the GHG Challenge and Registry program for the past six years.

While we are pleased with our past success, we can achieve much more. In 2006, we further defined our future course as an industry leader. New initiatives include a companywide inventory of greenhouse gas emissions and continued implementation of new emission reduction technology.

A greenhouse gas inventory, scheduled for completion by the end of 2007, is the backbone of our future emissions reduction program. Through the inventory we will identify reduction opportunities at Devon production facilities across North America. It will allow us to focus on specific regions, identify their needs and develop reduction strategies. Those efforts will include the application of new technology, improved production methods and better equipment configurations.

Protecting the natural environment is imperative in our field operations. Devon is the largest independent natural gas producer in New Mexico, where we have been working in harmony with the environment for more than 20 years.

Supervisor Jay Ewing examines a water sample at a Barnett Shale facility. Water recycling is an important element of Devon's conservation efforts.

Our ongoing emissions reduction efforts and our inventory program help position Devon for the future. By continually monitoring our performance and looking for opportunities to increase efficiency, we enhance our competitiveness as well as our ability to respond to potential changes in the regulatory environment. We are dedicated to operating compatibly with the environment, and we believe a dynamic and rigorous emissions reduction program is vital to that commitment.

Water Conservation Initiative Expanding in North Texas

Water is an integral part of natural gas production. Whether we are using fresh water to complete wells in the Barnett Shale, or managing brine from wells in the Rocky Mountains, water conservation is a core environmental initiative for Devon. For example, at a time when society's need for water is at an all-time high, Devon has responded by introducing recycling technology that will allow us to reduce our demand and potentially improve our efficiency companywide. Since 2005, Devon has partnered with Fountain Quail Water Management to pioneer recycling in the Barnett Shale natural gas field in north Texas.

Our efforts have resulted in the first water recycling program to be permitted for long-term use by industry regulators in the state of Texas. Devon's use of thermal distillation technology has allowed the company to reclaim water recovered from hydraulic fracture stimulations in the Barnett. Instead of injecting wastewater into deep disposal wells, Devon is using heat to separate the water from salt and other impurities. The treated water can be reused for future completion operations, taking demand pressure off local freshwater supplies.

Devon's recycling program has moved beyond the development stage. Today, we are operating seven recycling units with a combined treatment capacity of 500,000 gallons of water per day. As we bring additional units into the region, we expect our recycled volumes to continue growing. The impact of this technology could be meaningful. At full treatment capacity, up to 85 percent of the water we recover from fracture completions in the Barnett Shale could be reused, significantly reducing our demand for fresh water.

While we are pleased with our progress, we continue the push to develop new ideas. In March 2007, we began field testing a second water recycling technology in the Barnett Shale. We have developed the Engineered Membrane Separation system through a partnership with General Electric. The membrane technology uses a series of filters to treat water without the substantial energy requirements of the thermal system. If successful in the field, the new technology may prove to be more economical, and it could have applications in other natural gas producing regions.

By conserving water, we reduce our environmental impact and create opportunities to improve our operational efficiency. The program allows us to reduce the volume of water we must purchase for our operations, and it helps us avoid costs associated with saltwater disposal. Overall, water recycling is an exciting initiative for the company because of its benefits to the environment and to our bottom line.

“It has been my experience that Devon conducts its business with **innovation** and **professionalism**, carrying out its activities responsibly, with an eye toward protecting the environment.”

VICTOR CARRILLO
TEXAS RAILROAD COMMISSIONER
AUSTIN, TEXAS

“As a Texas Railroad Commissioner, I oversee and regulate the oil and gas industry. Devon is incredibly active in Texas and is the top gas producer in the state. It has been my experience that Devon conducts its business with innovation and professionalism, carrying out its activities responsibly, with an eye toward protecting the environment. For example, Devon has responded to freshwater use concerns in north Texas by being the first operator in Texas to test a pilot recycling program to recover water used in natural gas production operations.

“Devon is also pushing the envelope in terms of technological advancements, using innovations in seismic, drilling and production techniques in the Barnett Shale. They are the top producer in the unconventional Barnett Shale gas trend – perhaps the most active natural gas play in the nation. Along with their partners, they are also employing leading edge technology in successfully exploring the ultra-deepwater Lower Tertiary trend in the Gulf of Mexico. Devon is the type of producer we would like to see more of in Texas.”

"Our executives always stop to say hello. When I need to talk to them, their doors are always open, which is very helpful in the work that I do."

BILL WALTER
DEVON SUPERVISOR, INFRASTRUCTURE
AND DATABASE SERVICES
OKLAHOMA CITY, OKLAHOMA

"The rating agencies, banks and companies I work with all have a very high level of trust in us; they know we will follow through on our commitments."

JEFF RITENOUR
DEVON MANAGER,
CORPORATE FINANCE
OKLAHOMA CITY,
OKLAHOMA

"Whether we are working with other businesses or with government regulators, integrity is our focus. It's Devon's culture. Integrity guides us as professionals and influences us in our personal lives as well."

HUMBERTO QUINTAS
DEVON ATTORNEY AND LEGAL
COORDINATOR FOR EXPLORATION
AND PRODUCTION OPERATIONS
RIO DE JANEIRO, BRAZIL

"At Devon, every employee is treated with respect. Our leadership has created an environment of trust and goodwill, and it's apparent in how our teams work together."

JENIFER WICK
DEVON GEOSCIENCE TECHNICIAN
OKLAHOMA CITY, OKLAHOMA

"Since joining Devon in 1999, I've seen our management tested on repeated occasions. Each time they have demonstrated a commitment to doing what is right, even when it's not the most convenient or expedient solution."

DON SANDS
DEVON SUPERVISOR OF GULF
OF MEXICO OPERATIONS
LAFAYETTE, LOUISIANA

Management's Q&A

Resourcefulness Supports Our Strategy

How does Devon compete for qualified employees?

The vitality and growth of the energy industry is stretching the capacity of a maturing workforce. Competing for employees — from recent college graduates to experienced industry professionals — is challenging. Our college recruiting efforts include campus visits by younger employees who can share personal experiences and can relate to a student's uncertainty about their future. We also provide financial support for petroleum studies programs and facilities that raise our on-campus profile. In our college internship program we invite more than 100 students to spend the summer getting to know the company and working in the energy industry.

Experienced personnel are attracted by Devon's reputation as a leading independent oil and gas producer as well as by our culture of fairness and openness. Our objective is to hire and retain employees who are not only technically skilled but who are engaged and enthusiastic about Devon's future. To help retain our current staff, we gauge the practices of competitors to ensure that Devon offers comparable compensation and benefits programs. However, compensation alone is not enough to attract and retain the best people. We also believe that offering a superior work experience that rewards integrity, ingenuity and teamwork positions Devon as not only a great place to work, but more importantly, builds a strong base of leaders focused on creating value for our shareholders. An overview of the company's retention and recruiting programs can be found in the Careers section of Devon's website at devonenergy.com.

Do the Jack production test results apply to your other Lower Tertiary discoveries in the Gulf of Mexico?

The successful production test of the Jack well in 2006 was a significant indicator that deepwater Lower Tertiary reservoirs can produce oil in commercial quantities. Although each discovery is unique, the test results build our confidence in the commercial potential of Devon's Lower Tertiary portfolio. In addition, these results move us closer to the sanctioning and development of each of our discoveries in the Lower Tertiary.

Devon's four Lower Tertiary discoveries to date are similar, but not identical. Differences in water depths, reservoir characteristics, rock qualities, oil chemistry and other properties are present to varying degrees among the discoveries. The Jack well test answered many questions, but the learning process continues. As we develop our four Lower Tertiary projects and explore for additional Lower Tertiary discoveries, our understanding of this important new domestic energy source will expand rapidly.

Devon is already the biggest producer in the Barnett Shale. Can you continue to grow this asset?

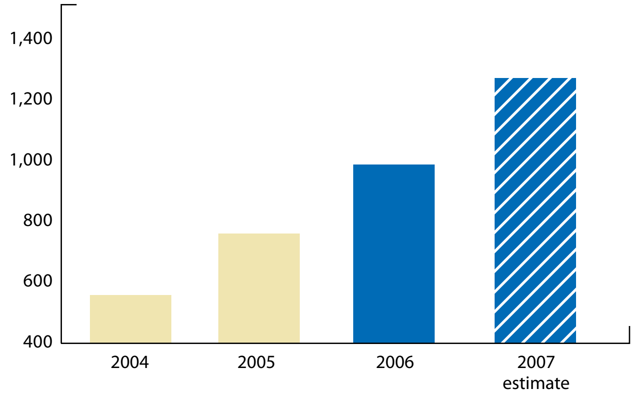
Yes, we are confident that we can continue to increase Devon's proved reserves and production from the Barnett Shale. We have more than doubled daily production from this outstanding unconventional resource since Devon first acquired its Barnett Shale properties in 2002. We have also doubled proved reserves in the Barnett to about 3.6 trillion cubic feet equivalent and have produced nearly one trillion cubic feet equivalent during the same period. These increases in gas production and proved reserves have been the result of an active drilling program complemented by technological improvements, including horizontal drilling, multi-stage completions and extensive 3-D computer imaging. Increased drilling density and enhanced reservoir management techniques have also led to production increases. We have more than tripled the number of producing wells in the Barnett Shale since 2002 to over 2,700 today.

In 2006, we acquired the properties of Chief Holdings, which increased Devon's land position in the field by 169,000 net acres to a current total of 736,000 net acres. Devon's acreage position is the largest in the Barnett Shale, and Devon is also the largest producer by a significant margin. Further growth in the Barnett will be achieved through high activity levels applied to this larger resource base and supplemented by continued enhancements in drilling and production technologies. We plan to drill at least 385 wells in 2007, and we have several thousand potential locations in inventory. Given these abundant drilling opportunities and our track record of success, we believe we can continue to increase the size and value of Devon's Barnett Shale assets far into the future.

What does your decision to reduce investment in conventional Canadian natural gas areas say about Devon's commitment to Canada?

Canada and the United States are two of the best places in the world to explore for and produce oil and gas. Stable governments and fiscal regimes, access to markets and a talented and experienced workforce attract us to North America. We have a large inventory of high quality assets in Canada and have had good performance in the past. However, in 2005 and 2006, the Canadian market for land, equipment, services and supplies became overheated. This, coupled with the stronger Canadian dollar, resulted in cost escalation that has severely squeezed profit margins — especially in the mature, conventional gas drilling

DEVON'S CUMULATIVE BARNETT SHALE PRODUCTION
(Net, Bcfe)



To date, Devon has produced in excess of one trillion cubic feet of natural gas from the Barnett Shale in north Texas.

SIGNIFICANT PROJECTS

PROJECT	OBJECTIVE	TARGET NET RATE
Barnett Shale	2009 peak production	>1.0 Bcfd
ACG Field	2007 average production	>30 MBoed
Merganser	1st production mid-2007	50 MMcfd
Polvo	1st production mid-2007	26 MBoed
Jackfish	2008 peak production	35 MBoed

Led by the Barnett Shale and other significant growth projects, Devon expects overall production to increase by 10% in 2007. Strong growth in the Barnett Shale is expected to continue into 2009.

areas. Devon responded by temporarily reducing the amount of capital allocated to these conventional project areas. We will continue to limit conventional drilling in Canada until the situation shows evidence of correcting. We will increase drilling in the conventional gas areas quickly, when conditions improve.

Elsewhere in Canada, such as at our Jackfish oil sands project and in the Lloydminster oil field, we are maintaining very active development programs. We expect to begin production from the initial phase of Jackfish this year. Combined production from an expanded Jackfish program and the Lloydminster area could reach 100,000 barrels per day early in the next decade.

Devon is forecasting 10% production growth from continuing operations in 2007. What projects are driving that growth?

We expect to produce from 219 million to 221 million oil-equivalent barrels, or Boe, in 2007. This is about 10% more than we produced in 2006, excluding production from Egypt and West Africa from both years. All of Devon's major geographic producing areas — the United States, Canada and international — are expected to participate in the growth.

In the United States, we anticipate continued production gains from our core onshore properties such as the Barnett Shale, Groesbeck and Carthage areas in Texas. We expect to see a third-quarter boost in gas production when the two deepwater Gulf of Mexico Merganser wells are tied into the Independence Hub. Our 50% interest in Merganser is estimated at about 50 million cubic feet, or roughly 8,000 Boe, per day. In Canada, the Jackfish oil sands project is expected to commence production in the second half of the year. Jackfish production should ramp up gradually until reaching its full capacity of about 35,000 Boe per day in 2008.

Outside North America, Devon's interest in the ACG field in Azerbaijan is projected to contribute more than 30,000 Boe per day to 2007 production. Oil production from ACG increased dramatically in the fourth quarter of 2006, following the payout of our carried working interest. In Brazil, the Polvo oil project is planned to come on stream in the summer of 2007. Oil production from Polvo is expected to quickly ramp up to about 26,000 barrels per day, net to Devon's interest. Together, these projects give us a high level of confidence that we will achieve our 10% growth target.

You invested $2.2 billion to acquire Chief Holdings in 2006. Can we expect more acquisitions ahead?

Much of Devon's historical growth came from large corporate mergers and acquisitions where we acquired entire companies. Our goal was to build a company with superior oil and gas assets that we could grow organically with the drill bit. At the same time we assembled a highly trained and motivated group of professionals who could use cutting edge technology to enhance that growth. With our last major corporate acquisition four years ago, we essentially accomplished that goal.

Today, Devon's companywide asset base is broad and diverse. Our long-term strategy is one of organic growth through exploration and development, supported by continuous improvement of our asset base. Our acquisition of Chief in 2006 was a tactical, targeted transaction. Chief's properties were located entirely in the Barnett Shale field in north Texas. Adding to our core positions, such as the Barnett Shale, and divesting assets that are not optimal for achieving our long-term objectives are important contributors to improving Devon's overall asset quality. Although we cannot completely rule out the possibility of another accretive corporate acquisition in the future, additional transactions, if any, are more likely to be focused, asset-driven acquisitions such as Chief.

"I like the way Devon has followed up on its acquisitions and has taken advantage of its opportunities. Their engineers and geologists have done some very good work, not only with the Barnett Shale assets Devon acquired from Mitchell, but also offshore in the Lower Tertiary trend, where Devon and its partners are working under very difficult conditions."

GEORGE MITCHELL
INVESTOR AND FORMER CHAIRMAN
AND CHIEF EXECUTIVE OFFICER OF
MITCHELL ENERGY & DEVELOPMENT CORP.
HOUSTON, TEXAS

"My job as a field engineer is to optimize production from our wells and work alongside others to identify opportunities for improvement. A lot of times, this means finding ways to cut costs and increase production from a single well."

KIM JOHNSTON
DEVON FIELD ENGINEER
GRANDE PRAIRIE, ALBERTA

"Whether it's safety, environmental responsibility, community involvement or our production operations, I know our senior management will support us when honesty and integrity are at the foundation of what we do."

GEORGE JACKSON
DEVON PRODUCTION SUPERVISOR
BRIDGEPORT, TEXAS

"I am very impressed with the attitude of Devon's management, particularly their willingness to use local resources, especially people from CNOOC. Devon allowed representatives from CNOOC to make a full technical contribution to the Panyu field development. As a result, the two companies created a very efficient process that allowed us to develop the Panyu field into one of the most successful offshore oil projects in the region."

DUAN CHENG GANG
VICE PRESIDENT OF FIELD
DEVELOPMENT AND
ENGINEERING
CHINESE NATIONAL OFFSHORE
OIL COMPANY (CNOOC)
SHENZHEN, GUANGDONG
PROVINCE, CHINA

"We are a close group with a great **team** spirit. As a result, we come to work each day believing we can make an **impact** on the company by generating good exploration prospects which lead, hopefully, to major new discoveries for our future."

GREG KELLEHER (CENTER)
DEVON DEEPWATER MANAGER
GULF DIVISION
HOUSTON, TEXAS

FROM LEFT TO RIGHT: **IRMA CASTRO,** DATABASE SUPERVISOR; **DARRYL LINTON,** ENGINEER; **GREG KELLEHER,** DEEPWATER MANAGER; **ROBBIE SENG,** GEOLOGIST; **ADAM SEITCHIK,** GEOPHYSICIST

"When I joined Devon through the company's acquisition of PennzEnergy in 1999, what impressed me was how much emphasis the company placed on its values. Trust, collegiality and goodwill are among those values, and they have special importance to me and the people in my group.

"We are responsible for generating exploration prospects and developing production in the Gulf of Mexico's deep water, which is one of the most technologically challenging places in the world to operate. We overcome those obstacles by working in an environment that encourages trust, creative thinking and collective effort. If there is no trust, there is no communication or sharing of ideas. Trusting environments allow good ideas to nurture and mature.

"We are a close group with a great team spirit. As a result, we come to work each day believing we can make an impact on the company by generating good exploration prospects which lead, hopefully, to major new discoveries for our future."

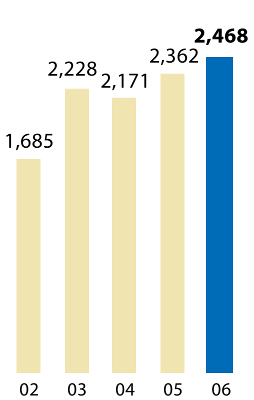
Exploration and Production Resources

Developing Our Full Potential

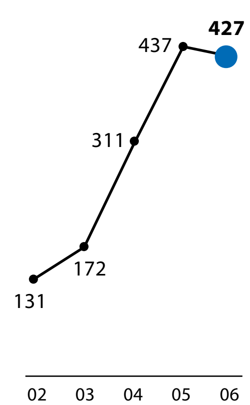
As one of the world's largest independent exploration and production companies, Devon is a leader in the search for new oil and natural gas resources. In 2006, we increased reserves in the ground and positioned the company for future growth. We increased estimated proved reserves by 13% in 2006 to a record 2.4 billion oil-equivalent barrels. We produced 200 million equivalent barrels from continuing operations in 2006 and expect to produce 219 million to 221 million equivalent barrels in 2007.

During the past year we drilled nearly 2,500 wells with an overall success rate of 98%. Our repeatable, low-risk development drilling projects were enhanced by high-impact exploration successes in the deepwater Gulf of Mexico. Also during 2006, we moved several multi-year oil and gas projects toward completion. The following pages profile some of Devon's more significant exploration and production projects.

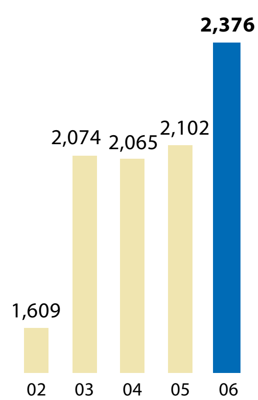
WELLS DRILLED



RESERVE ADDITIONS FROM EXTENSIONS, DISCOVERIES AND PERFORMANCE REVISIONS
(MMBoe)



PROVED RESERVES
(net of royalties) (MMBoe)



Devon drilled a record 2,468 wells in 2006, adding 427 million equivalent barrels of proved reserves with the drill bit. Total proved reserves reached a record 2.376 billion barrels at year-end.

As the largest gas producer in Texas, Devon drills day and night to help meet the nation's energy needs. We drilled our 600th horizontal well in the Barnett Shale in 2006.

In addition to being the largest gas producer in the Barnett Shale, Devon also owns and operates an extensive network of natural gas gathering and processing facilities.

Barnett Shale, a Lasting Resource

The Barnett Shale in north Texas has been called the hottest natural gas play in the United States, and Devon is its largest producer. Since acquiring our original ownership in the field in 2002, we have drilled about 1,600 wells and increased our net daily production from 350 million cubic feet of natural gas equivalent to more than 710 million today.

In 2006, we leapt further ahead in the play by acquiring the assets of another Barnett operator, Chief Holdings. Devon acquired more than 600 billion cubic feet of proven natural gas reserves through the $2.2 billion transaction. Importantly, the deal also grew our land position to 736,000 net acres, representing thousands of potential drilling locations.

Devon's dominance in the low-risk Barnett Shale is reaping huge rewards for the company and our shareholders. We now have more than 2,700 producing wells in the Barnett, representing one-third of Devon's total gas production in the United States. Devon produces nearly half the field's overall daily production and more than twice that of our nearest competitor.

Application of technology is an important element of Devon's leadership position in the Barnett. We first introduced horizontal drilling to the play in 2002 and drilled our 600th horizontal Barnett Shale well in 2006. We have also partnered with a leading university to develop proprietary, cutting-edge underground imaging to identify optimal drilling locations.

We are accelerating production growth in the Barnett by increasing drilling density. The 20-acre infill program we started in 2005 is delivering impressive results, and we have now begun drilling 20-acre wells outside the borders of the original core pilot area. The successful infill program, the addition of Chief's assets and expansion of our operations in Johnson and Parker counties are currently keeping 30 drilling rigs running. We plan to drill at least 385 wells in 2007, and by late 2009 we expect our Barnett production to reach one billion cubic feet of natural gas equivalent per day.

The Barnett Shale is one of the country's most important new sources of clean-burning natural gas, and it represented 26% of Devon's companywide reserve base at year-end 2006. Since 2002, we have significantly increased the amount of gas we are recovering from the Barnett Shale, and we expect additional technological advances in the future to further increase recoveries. The Barnett Shale is one of Devon's most prized assets and it will likely remain so for many years to come.


THE WALL STREET JOURNAL.

SOUTH SLOPE

Oil Find Will Spur Industry Change

New, Deep-Water Well Boosts U.S. Reserves; A Bonanza for Chevron

Deep Discovery

A front page story in *The Wall Street Journal* captured the significance of the Jack No. 2 well test.

During testing, the Jack No. 2 well in the Gulf of Mexico flowed at a rate of more than 6,000 barrels of oil per day.

Jack Test Brings Worldwide Attention

Seldom does a single business story catch the attention of news media around the world. This was the case, however, when in September 2006 Devon and its co-owners announced the successful test of the deepwater Jack No. 2 well in the Gulf of Mexico. According to *The Wall Street Journal*, the Gulf's Lower Tertiary trend "could become the nation's biggest new domestic source of oil since the discovery of Alaska's North Slope more than a generation ago."

The Jack test made news, and it was big news for Devon because we have four significant discoveries in this exciting new oil play. The production test proved that oil found in the 2004 Jack discovery would flow to the surface at commercial rates. During the test, the Jack No. 2 flowed at a rate of more than 6,000 barrels per day from just 40% of the oil-bearing column. Future plans for Jack include drilling another appraisal well to better define the size of the field. Also ahead, the co-owners will decide upon the layout and engineering designs to develop the field.

Devon is further along with plans to commercially develop Cascade. This 2002 discovery was our first in the Lower Tertiary. Beginning in late 2009, Cascade is expected to produce into the first floating production, storage and offloading vessel (FPSO) approved for the Gulf of Mexico. FPSOs enable offshore production in frontier areas such as the Lower Tertiary trend before pipeline infrastructure has been built.

We made our fourth discovery in the Lower Tertiary trend in 2006. The discovery well, on the Kaskida prospect, also appears to be the largest of the four. Future plans for Kaskida include additional appraisal drilling and evaluation of various development options. With the addition of Kaskida, Devon's Lower Tertiary discoveries to date may hold up to 900 million barrels of resource potential. On top of that, we have another 18 undrilled prospects with a combined unrisked resource potential more than double Devon's current reserve size of 2.4 billion oil-equivalent barrels.

Horizontal Drilling Capturing More Gas Resources

A typical oil or gas well is drilled straight down, vertically. A horizontal well starts out vertically but is turned underground to run parallel to the surface. To visualize the benefits of horizontal drilling, imagine the earth's surface as the top of a sandwich. If you push a drinking straw between the slices of bread, you will encounter a lot more peanut butter than you will by sticking the straw through the sandwich like a tooth pick. When positioned properly, one horizontal well can recover as much oil or natural gas as three or four vertical wells. This can improve well economics significantly, because the cost of a horizontal well may be only two to three times the cost of a vertical well.

In east Texas, Devon is applying the same horizontal drilling and completion technologies that we have honed in the Barnett Shale field while drilling more than 600 successful horizontal wells. Devon drilled its first horizontal well in east Texas in 2005 in the Nan-Su-Gail field within the Groesbeck area. We continued the Nan-Su-Gail program in 2006, achieving initial production rates of 11.5 million and 26 million cubic feet of gas per day from the first two wells and 32 million cubic feet per day from a third. We have 100% working interests in these wells and could have as many as 200 additional drilling locations throughout the Groesbeck area.

Oil from the Devon-operated Polvo project in Brazil will flow to this 1.5 million barrel vessel.

Polvo is located on block BM-C-8, one of nine Brazilian offshore exploratory blocks held by Devon.

Following our success at Groesbeck, we began trying horizontal drilling further east in the Carthage area. The first well in the Carthage program also began producing at an impressive rate — averaging about nine million cubic feet per day for the first 30 days of production. We plan to continue evaluating horizontal drilling at Carthage, where we could have up to 70 potential drilling locations.

Woodford Shale Shows Promise

With the tremendous success of the Barnett Shale in north Texas, the oil and gas industry is searching for other look-alike shale plays. One such candidate is the Woodford Shale in the Arkoma basin of eastern Oklahoma. The Woodford and Barnett are not identical, but share some characteristics. Both contain large quantities of natural gas, and both formations give up their gas reluctantly. As in the Barnett Shale, Woodford wells must be hydraulically fractured during completion. This adds to the cost and complexity of each well. Also, as in the Barnett Shale, the Woodford responds well to horizontal drilling.

Devon has assembled an acreage position in several eastern Oklahoma counties that is prospective for the Woodford Shale. We currently hold about 70,000 net acres, representing several hundred potential drilling locations. We drilled our first Woodford well in 2005 and drilled 40 horizontal Woodford wells in 2006. We plan to keep four operated rigs running on our Woodford acreage in 2007, drilling 55 wells.

The Octopus is Coming

Polvo, octopus in Portuguese, is Devon's first start-to-finish offshore oil project in Brazil. Located in the Campos Basin, Polvo will be one of the quickest offshore projects brought to completion in Brazil. Discovered in June 2004, Polvo is expected to see first production in mid-2007. Development plans anticipate 10 producing wells. The 1.5 million barrel-capacity FPSO vessel that will handle the produced oil has been commissioned and is expected on location in May. Oil production is projected to reach a peak of about 26,000 barrels of oil per day, net to Devon. We operate Polvo with a 60% working interest.

Encouraged by our success at Polvo, Devon's objective is to build a significant presence in Brazil through an ongoing exploration program. Brazil welcomes foreign investment to make the country more energy self-sufficient. Devon has even joined with Brazil's own Petrobras to acquire leases in some of the country's most promising offshore exploration areas. Petrobras is a worldwide leader in deepwater oil and gas exploration and production, and we are very pleased to be partnered with this company in its home country, as well as in the U.S. Gulf of Mexico. We currently hold leases in nine offshore blocks in Brazil.

Construction nears completion at Devon's Jackfish thermal oil facility in Alberta, Canada. Commencement of steam injection and first production from Jackfish are planned for 2007.

Drilling operations on the ACG field, offshore Azerbaijan, have increased field-wide production to more than 700,000 barrels of oil per day. Devon's share of production is expected to average more than 30,000 barrels per day in 2007.

First Production Slated for Jackfish Oil Sands Project

The oil sands of western Canada are believed to hold billions of barrels of oil in the form of thick, tar-like bitumen. Shallow deposits of bitumen have been successfully mined for many years. Deeper deposits cannot be mined, but can be heated and coaxed to the surface by injecting steam underground. Devon's 100%-owned Jackfish project in eastern Alberta utilizes the steam-assisted gravity drainage (SAGD) process.

Jackfish, with 300 million barrels of estimated recoverable reserves, has been under construction since 2005. With construction nearing completion, we expect to begin injecting steam at Jackfish in 2007. As the steam permeates and heats the bitumen, flows will increase, reaching an expected 35,000 barrels per day in late 2008. Jackfish is an important component of our production growth forecasts for 2008 and 2009. Without the declines seen in most conventional oil fields, Jackfish is expected to produce at a relatively steady rate for 20 years or more.

We have also asked the Alberta government to approve a second phase Jackfish project on our oil sands leases adjacent to the first phase. This would double the resource size to approximately 600 million barrels and double production to about 70,000 barrels per day. If the expansion project is approved and sanctioned for development, first steam at Jackfish 2 could commence near the end of this decade.

Production Growth from the Caspian

Azerbaijan has a rich heritage as an oil producer. It was the birthplace of the oil-refining industry and was the world's leading petroleum producer at the beginning of the twentieth century. During World War II, the country supplied about 70% of the former Soviet Union's total oil production.

The Azeri-Chirag-Gunashli (ACG) oil development project is located in the Caspian Sea, nearly 75 miles off the coast of Azerbaijan. ACG is one of the largest oil fields under development in the world, and Devon's share represents about 84 million barrels of light, sweet crude oil.

Devon established its stake in the field in 1999 when we acquired PennzEnergy. Commercial development of ACG was dependent upon construction of a major export pipeline that was completed in 2006. For the past seven years, most of Devon's share of production from ACG went to repay partners for costs incurred on our behalf under the terms of our 5.6% carried interest ownership. A ramp-up in production upon completion of the export pipeline enabled us to repay our carried interest balances in late 2006.

With transportation capacity provided by the export pipeline, field-wide production has increased to more than 700,000 barrels per day, heading to a million barrels per day in 2009. As a result, Devon's share of ACG production has also increased, making ACG a significant contributor to our 10% year-over-year production growth forecast for 2007. Devon's production from ACG is expected to average more than 30,000 barrels per day in 2007.

Operating Statistics by Area (1)

	Permian	Mid-Continent	Rocky Mountains	Gulf Coast	U.S. Offshore	Total U.S.	Canada	International	Total Company
Producing Wells at Year-End	8,704	6,668	5,785	3,925	687	25,769	7,391	530	33,690
2006 Production (Net of royalties)									
Oil (MMBbls)	7	1	1	2	8	19	13	23	55
Gas (Bcf)	38	225	95	129	79	566	241	8	815
NGLs (MMBbls)	2	11	1	4	1	19	4	—	23
Oil, Gas and NGLs (MMBoe)	16	49	18	27	22	132	58	24	214
Average Prices									
Oil price ($/Bbl)	$ 61.20	62.49	55.40	63.11	64.24	62.23	46.94	61.36	58.30
Gas price ($/Mcf)	$ 5.80	5.75	5.64	6.39	7.24	6.09	6.05	3.95	6.06
NGLs price ($/Bbl)	$ 28.78	28.21	15.63	34.05	35.43	29.42	42.67	—	32.10
Oil, Gas and NGLs ($/Boe)	$ 45.40	33.52	35.35	39.27	51.23	39.31	39.21	59.24	41.51
Year-End Reserves (Net of royalties)									
Oil (MMBbls)	89	6	20	12	43	170	329	209	708
Gas (Bcf)	265	3,382	1,134	1,198	376	6,355	1,896	105	8,356
NGLs (MMBbls)	22	156	7	45	3	233	42	—	275
Oil, Gas and NGLs (MMBoe)	155	725	216	257	109	1,462	687	227	2,376
Year-End Present Value of Reserves (In millions) (2)									
Before income tax	$ 2,178	4,334	1,952	1,890	2,285	12,639	6,714	4,742	24,095
After income tax	$					8,677	4,817	3,079	16,573
Year-End Leasehold (Net acres in thousands)									
Developed	308	772	550	552	223	2,385	2,124	299	4,808
Undeveloped	469	603	1,409	545	1,499	4,525	6,304	9,440	20,269
Wells Drilled During 2006	171	621	515	223	20	1,550	877	41	2,468
Capital Costs Incurred (In millions) (3)									
2006 Actual (4)	$ 216	3,609	365	666	681	5,537	1,554	631	7,722
2007 Forecast	$ 220-240	1,515-1,625	350-370	805-875	720-775	3,610-3,885	1,245-1,350	395-440	5,250-5,675

(1) Excludes results from discontinued operations.
(2) Estimated future revenue to be generated from the production of proved reserves, net of estimated future production and development costs, discounted at 10% in accordance with SFAS No. 69, *Disclosures about Oil and Gas Producing Activities*. Devon believes that the pre-tax 10% present value is a useful measure in addition to the after-tax value as it assists in both the determination of future cash flows of the current reserves as well as in making relative value among peer companies. The after-tax present value is dependent on the unique tax situation of each individual company while the pre-tax present value is based on prices and discount factors which are consistent from company to company. We also understand that securities analysts use this pre-tax measure in similar ways.
(3) 2006 actual costs incurred and 2007 forecasted capital costs include exploration and production expenditures, capitalized general and administrative costs, capitalized interest costs and asset retirement costs.
(4) 2006 costs incurred includes acquisition costs of $2.2 billion in the Mid-Continent region related to the Chief acquisition.

11-Year Property Data (1)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	5-Year Compound Growth Rate	10-Year Compound Growth Rate
Reserves (Net of royalties)													
Oil (MMBbls)	351	219	166	439	406	527	444	646	585	640	708	6%	7%
Gas (Bcf)	1,131	1,403	1,440	2,785	3,045	5,024	5,836	7,316	7,493	7,296	8,356	11%	22%
NGLs (MMBbls)	18	24	21	55	50	108	192	209	232	246	275	21%	31%
Oil, Gas and NGLs (MMBoe)	558	477	427	958	963	1,472	1,609	2,074	2,065	2,102	2,376	10%	16%
10% Present Value Before Income Taxes (In millions) (2)	$ 3,952	2,100	1,375	5,316	17,075	6,687	15,307	22,438	22,693	34,830	24,095	29%	20%
Production (Net of royalties)													
Oil (MMBbls)	30	29	20	25	37	36	42	60	74	62	55	9%	6%
Gas (Bcf)	116	180	189	295	417	489	761	863	891	827	815	11%	22%
NGLs (MMBbls)	2	3	3	5	7	8	19	22	24	24	23	24%	27%
Oil, Gas and NGLs (MMBoe)	52	62	55	79	113	126	188	226	247	224	214	11%	15%
Average Prices													
Oil (Per Bbl)	$ 17.49	17.03	12.28	17.78	24.99	21.41	21.71	25.82	28.22	38.00	58.30	22%	13%
Gas (Per Mcf)	$ 1.82	2.04	1.78	2.09	3.53	3.84	2.80	4.51	5.32	6.99	6.06	10%	13%
NGLs (Per Bbl)	$ 13.78	12.61	8.08	13.28	20.87	16.99	14.05	18.65	23.04	28.96	32.10	14%	9%
Oil, Gas and NGLs (Per Boe)	$ 14.90	14.51	11.09	14.22	22.38	22.19	17.61	25.93	29.92	39.48	41.51	13%	11%
Unit Production and Operating Expense (Per Boe)	$ 5.24	4.63	4.29	4.15	4.81	5.29	4.71	5.65	6.13	7.42	8.54	10%	5%

(1) The years 1996 through 2002 exclude results from Devon's operations in Indonesia, Argentina and Egypt that were discontinued in 2002. Devon acquired new assets in Egypt from the April 2003 Ocean merger. The years 2003 through 2006 exclude results from operations in Egypt that were discontinued in 2006. Data has been restated to reflect the 1998 merger of Devon and Northstar and the 2000 merger of Devon and Santa Fe Snyder in accordance with the pooling-of-interests method of accounting.
(2) Estimated future revenue to be generated from the production of proved reserves, net of estimated future production and development costs, discounted at 10% in accordance with SFAS No. 69, *Disclosures about Oil and Gas Producing Activities*. Devon believes that the pre-tax 10% present value is a useful measure in addition to the after-tax value as it assists in both the determination of future cash flows of the current reserves as well as in making relative value among peer companies. The after-tax present value is dependent on the unique tax situation of each individual company while the pre-tax present value is based on prices and discount factors which are consistent from company to company. We also understand that securities analysts use this pre-tax measure in similar ways.

Key Property Highlights

PERMIAN

A / Southeast New Mexico

Profile
- 75% average working interest in 548,000 acres.
- Key fields include Ingle Wells, Catclaw Draw, Potato Basin, Red Lake, Gaucho, and Outland.
- Produces oil and gas from multiple formations at 1,500' to 16,500'.
- 44.2 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity
- Drilled and completed 33 gas wells.
- Drilled and completed 49 oil wells.
- Recompleted 15 wells.

2007 Plans
- Drill 28 gas wells.
- Drill 43 oil wells.
- Recomplete 35 wells.

B / West Texas

Profile
- 40% average working interest in 1.1 million acres.
- Key fields include Wasson, Reeves and Anton-Irish to the north; Ozona, Keystone/Kermit and Waddell to the south.
- Produces oil and gas from multiple formations at 2,500' to 18,000'.
- 111.3 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity
- Drilled and completed 12 gas wells.
- Drilled and completed 83 oil wells.
- Recompleted 52 wells.
- Reactivated 11 wells.

2007 Plans
- Drill 29 gas wells.
- Drill 71 oil wells.
- Recomplete 48 wells.
- Reactivate 20 wells.

MID-CONTINENT

A / Woodford Shale

Profile
- 70,000 net acres in the Arkoma Basin in eastern Oklahoma.
- Operated working interests range from 50% to 100%.
- Emerging unconventional natural gas play.
- Produces gas from the Woodford Shale formation at 4,000' to 10,000'.
- 10.4 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity
- Drilled 40 horizontal wells (15 operated).
- Acquired additional acreage.
- Acquired 3-D seismic.

2007 Plans
- Drill 55 horizontal wells (40 operated).
- Expand gas gathering system capacity.
- Continue construction of 200 million cubic feet per day gas plant.
- Acquire additional 3-D seismic and acreage.

B / Barnett Shale

Profile
- 736,000 net acres (127,000 within core area) in the Fort Worth Basin of north Texas.
- >93% average working interest in core.
- >84% average working interest outside core.
- Produces gas from the Barnett Shale formation at 6,500' to 9,200'.
- 608.1 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity
- Drilled 133 wells within core area, including:
  - 54 vertical infill wells.
  - 79 horizontal wells.
- Drilled 250 wells outside core area, including:
  - 7 vertical wells.
  - 243 horizontal wells.
- Acquired Chief's assets.
- Improved drilling efficiencies with new generation rigs.
- Acquired 3-D seismic and acreage.

2007 Plans
- Drill 157 wells within core area, including:
  - 10 vertical infill wells.
  - 147 horizontal wells.
- Drill 228 horizontal wells outside core area.
- Evaluate far west acreage.
- Acquire additional 3-D seismic and acreage.

ROCKY MOUNTAINS

A / Bear Paw

Profile
- 814,000 net acres in north central Montana.
- 90% average working interest in federal units.
- 75% average working interest outside federal units.
- Produces gas from the Eagle formation at 800' to 2,000'.
- 18.5 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity
- Drilled and completed 49 wells.
- Recompleted 23 wells.
- Installed artificial lift on 39 wells.
- Expanded gas gathering system capacity.

2007 Plans
- Drill 95 wells.
- Continue workover program.
- Add compression and perform other gas gathering system improvements.
- Acquire 3-D seismic.

B / Powder River Coalbed Natural Gas

Profile
- 75% average working interest in 346,000 acres in north eastern Wyoming.
- Produces coalbed natural gas from the Fort Union Coal formations at 300' to 2,000'.
- 19.3 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity
- Drilled 251 coalbed natural gas wells.
- Added compression and performed other gas gathering system improvements.
- Increased outside operated activity in Juniper Draw area (Big George coal).

2007 Plans
- Drill 342 coalbed natural gas wells.
- Continue focus and expansion of operated and outside operated activity at Juniper Draw.
- Initiate full scale development plans for West Pine Tree Unit.

C / Washakie

Profile
- 76% average working interest in 210,000 acres in southern Wyoming.
- Produces gas from multiple formations at 6,800' to 10,300'.
- 104.4 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity
- Drilled and completed 137 wells.
- Recompleted 3 wells.
- Installed 76 plunger lifts.
- Installed compression and performed other gas gathering system improvements.
- Continued implementation of automated production control system.

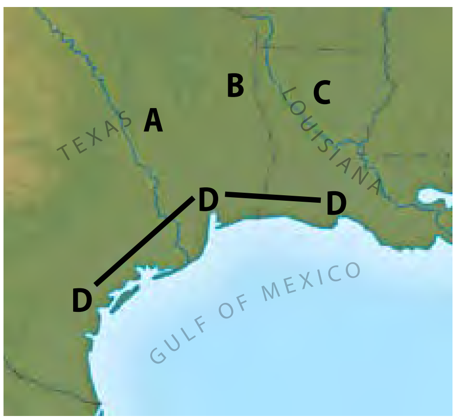
2007 Plans
- Drill 105 wells, including 23 directional wells.
- Install 100 plunger lifts.
- Add compression and perform other gas gathering system improvements.
- Continue implementation of automated production control system.

D / NEBU/32-9 Units

Profile
- 25% average working interest in 54,000 acres in the San Juan Basin of northwestern New Mexico.
- Coalbed natural gas development began in the late 1980s and early 1990s.
- Includes 299 coalbed gas wells, 262 conventional wells, gas and water gathering systems and an automated production control system.
- Produces primarily coalbed natural gas from the Fruitland Coal formation at 3,500'.
- 18.1 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity
- Drilled and completed 32 coalbed gas wells.
- Completed 171-well workover program.
- Drilled and completed 20 conventional gas wells.
- Recompleted 4 conventional wells.

2007 Plans
- Drill 4 coalbed gas wells.
- Initiate 150-well workover program.
- Drill 33 conventional gas wells.
- Recomplete 6 conventional wells.



GULF COAST

A / Groesbeck Area

Profile
- 72% average working interest in 292,000 acres in east central Texas.
- Key fields include Personville, Nan-Su-Gail, Dew, Oaks and Bald Prairie.
- Produces primarily gas from the Travis Peak, Cotton Valley Sand, Bossier and Cotton Valley Lime formations at 6,000' to 13,000'.
- Includes 677 producing wells.
- 48.0 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity
- Drilled and completed 23 vertical wells.
- Drilled and completed 8 horizontal wells.
- Recompleted 3 wells.
- Acquired additional acreage through joint venture.

2007 Plans
- Drill 22 vertical wells.
- Drill 12 horizontal wells.
- Drill 1 exploratory well on joint-venture acreage.
- Recomplete 9 wells.
- Acquire 3-D seismic.

B / Carthage Area

Profile
- 85% average working interest in 205,000 acres in east Texas.
- Key fields include Carthage, Bethany, Waskom, Stockman and Appleby.
- Produces primarily gas from the Pettit, Travis Peak and Cotton Valley formations at 5,700' to 9,600'.
- Includes 1,530 producing wells.
- 160.8 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity
- Drilled and completed 120 vertical wells, including 36 infill wells.
- Drilled and completed 2 horizontal wells.
- Recompleted 88 wells.
- Acquired additional acreage.

2007 Plans
- Drill 136 vertical wells, including 18 infill wells.
- Drill 14 horizontal wells.
- Recomplete 48 wells.

C / North Louisiana Area

Profile
- 65% average working interest in 654,000 acres in north Louisiana.
- Own mineral interests in 139,000 net acres on trend with lower Cotton Valley/Bossier play.
- Emerging gas exploration play.
- Produces from the lower Cotton Valley and Bossier formations at 13,000' to 17,000'.
- Includes 44 producing wells.
- 2.4 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity
- Drilled and completed 5 wells at Vernon-Ansley.
- Drilled 1 exploratory discovery well at East Vernon.
- Drilled 2 appraisal wells at East Vernon.
- Drilled 1 exploratory well at Mt. Moriah.
- Drilled 1 appraisal well at Vixen.
- Acquired 3-D seismic at Vixen and Caney Lake.

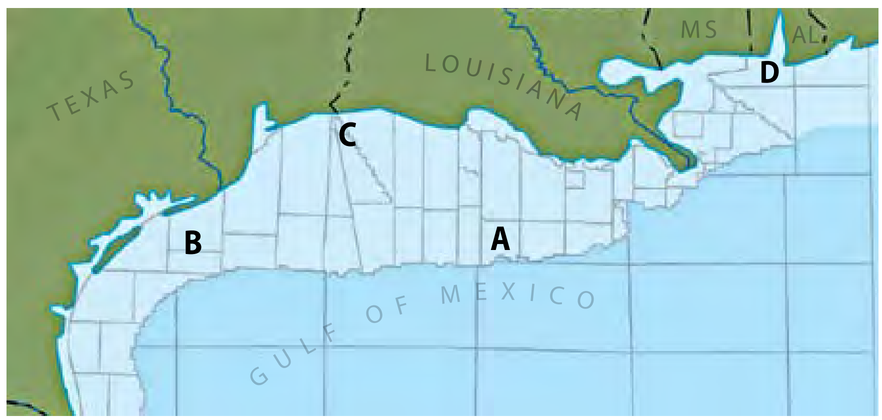
2007 Plans
- Drill 2 exploration wells to test other prospect areas.

D / South Texas/South Louisiana

Profile
- 66% average working interest in 584,000 acres.
- Key areas include Matagorda, Zapata, Agua Dulce/N. Brayton, Duval/Hagist, Houston, Central Texas, Coastal Frio and the Patterson field in Louisiana.
- Produces oil and gas from the Frio/Vicksburg, Yegua, Wilcox and Woodbine trends at 1,500' to 15,000'.
- Includes 930 producing wells.
- 30.9 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity
- Drilled and completed 44 wells.
- Drilled 4 exploratory wells in the Matagorda area.
- Recompleted 62 wells.
- Acquired 3-D seismic in the Zapata area.

2007 Plans
- Drill 49 wells.
- Drill 1 exploratory well in the Matagorda area.
- Drill 3 exploratory wells in south Louisiana.
- Drill 2 horizontal Austin Chalk wells.
- Recomplete 63 wells.
- Acquire 3-D seismic in the Brazoria area.
- Acquire 3-D seismic in the Patterson field.



GULF - SHELF

A / Eugene Island South Area

Profile
- Includes 8 blocks located in the southern portion of Eugene Island area.
- Working interests range from 14% to 100%.
- Located offshore Louisiana in 250' of water.
- Produces oil and gas from sands at 1,500' to 13,000'.
- 14.7 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity
- Drilled 2 wells at Eugene Island 315.
- Drilled 2 wells at Eugene Island 316.
- Drilled 1 well at Eugene Island 329.
- Drilled 1 well at Eugene Island 337.
- Completed 2005 Chopin discovery and commenced production.
- Drilled 1 dry hole at Eugene Island 334.

2007 Plans
- Drill 2 wells at Eugene Island 337.
- Drill 1 well at Eugene Island 333.
- Drill 1 well at Eugene Island 334.
- Initiate recompletion program at Eugene Island 330.

Shelf Exploration Prospects

Profile

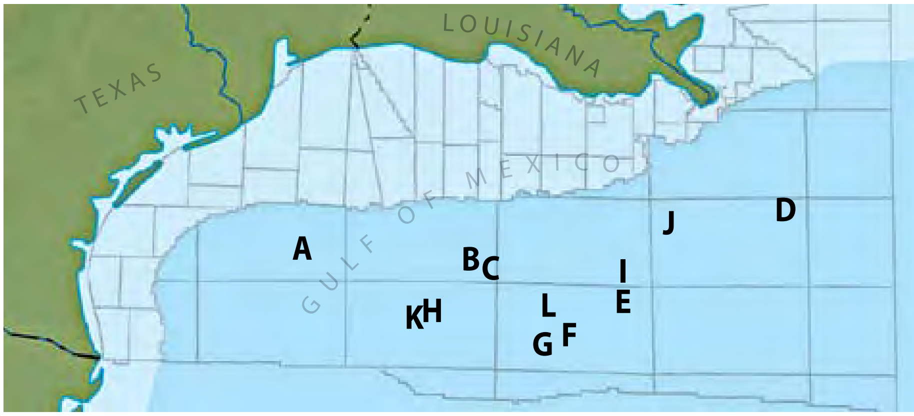
B / Nimitz
- Brazos A-24.
- Located offshore Texas in 130' of water.
- Target formation: Miocene sands at 19,400' to 20,700'.
- 20% working interest.
- Net unrisked reserve potential: undisclosed.

C / Buckeye
- West Cameron 164.
- Located offshore Louisiana in 50' of water.
- Target formation: Lower Miocene sands at 9,000' to 13,000'.
- 100% working interest.
- Net unrisked reserve potential: 4 million barrels of oil equivalent.

D / Sleeping Bear
- Mobile 826.
- Located offshore Alabama in 50' of water.
- Target formation: Norphlet sands at 21,200' to 21,800'.
- 75% working interest.
- Net unrisked reserve potential: 16 million barrels of oil equivalent.

2006 Activity
- Finalized geophysical analyses and drilling contracts.
- Secured farmin agreement at Nimitz.

2007 Plans
- Secure farmout agreements with industry partners at Sleeping Bear and Buckeye.
- Drill exploratory test wells.



GULF - DEEPWATER

A / Nansen

Profile

- Includes 3 blocks in central East Breaks area.
- 50% working interest.
- Located offshore Texas in 3,500' of water.
- Produces oil and gas from sands at 9,000' to 14,000'.
- Utilizes the world's first open-hull truss spar.
- 36.2 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity

- Conducted geophysical analysis for 2-well development program in 2007.

2007 Plans

- Drill 2 development wells.
- Recomplete 2 wells.

B / Magnolia

Profile

- 25% working interest in Garden Banks 783 and 784.
- Located offshore Louisiana in 4,700' of water.
- Developing 1999 discovery.
- Produces oil and gas from sands at 12,000' to 17,000'.
- Utilizes the world's deepest tension-leg platform.
- 13.9 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity

- Completed final 2 of initial 8 wells.

2007 Plans

- Drill 2 additional development wells.
- Perform recompletions and sidetrack drilling as necessary.
- Evaluate potential for additional drilling.

C / Red Hawk

Profile

- 50% working interest in Garden Banks 876, 877, 920 and 921.
- Located offshore Louisiana in 5,300' of water.
- 2001 discovery.
- Produces gas from sands at 16,000' to 18,500'.
- Utilizes the world's first cell spar.
- 6.1 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity

- Restored production previously shut-in due to hurricane damage to third-party downstream facilities.

2007 Plans

- Install compression.
- Evaluate potential for additional drilling.

D / Merganser (Independence Hub)

Profile

- 50% working interest in Atwater Valley 37.
- Located offshore Louisiana in 8,100' of water.
- Developing 2001 discovery.
- To produce gas from sands at 19,000' to 20,000'.
- Cooperative development of 10 nearby industry discoveries utilizing subsea tie-backs to a central production hub.
- 7.2 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity

- Completed and tested 2 future producing wells.
- Continued construction and installation of surface and subsea facilities.

2007 Plans

- Finish installation of surface and subsea facilities.
- Commence production.

Lower Tertiary Discoveries

Profile

E / Cascade

- 50% working interest in Walker Ridge 206.
- Located offshore Louisiana in 8,200' of water.
- Target formation: Lower Tertiary sands at 25,000' to 27,000'.
- Discovery well drilled in 2002 encountered > 450' of net oil pay.

F / St. Malo

- 22.5% working interest in Walker Ridge 678.
- Located offshore Louisiana in 6,900' of water.
- Target formation: Lower Tertiary sands at 26,000' to 29,000'.
- Discovery well drilled in 2003 encountered > 450' of net oil pay.

G / Jack

- 25% working interest in Walker Ridge 759.
- Located offshore Louisiana in 7,000' of water.
- Target formation: Lower Tertiary sands.
- Discovery well drilled in 2004 encountered > 350' of net oil pay.

H / Kaskida

- 20% working interest in Keathley Canyon 292.
- Located offshore Louisiana in 5,900' of water.
- Target formation: Lower Tertiary sands.
- Discovery well drilled in 2006 encountered approximately 800' of net hydrocarbon bearing sands.
- First Lower Tertiary discovery in Keathley Canyon area.

2006 Activity

- Increased ownership in Cascade unit from 25% to 50%.
- Announced plans to develop Cascade with first production in late 2009.
- Received approval from MMS for Cascade Conceptual Plan using an FPSO.
- Completed first successful Lower Tertiary production test at Jack.
- Drilled discovery well at Kaskida.
- Drilled sidetrack appraisal well at Kaskida.
- Evaluated development options and facilities designs for Cascade, Jack and St. Malo.
- Acquired 13 additional Lower Tertiary blocks through federal lease sale.
- Secured 2 long-term deepwater rig contracts.

2007 Plans

- Sanction initial development at Cascade.
- Obtain MMS approval of Deepwater Operating Plan at Cascade.
- Initiate drilling second appraisal well at Jack.
- Initiate drilling second appraisal well at St. Malo.
- Continue evaluation of development options at Jack and St. Malo.
- Initiate evaluation of development options at Kaskida.
- Conduct additional appraisal operations at Kaskida

Miocene Discoveries

Profile

I / Mission Deep

- 50% working interest in Green Canyon 955.
- Located offshore Louisiana in 7,300' of water.
- Target formation: Miocene sands.
- Discovery well drilled in 2006 encountered > 250' of net oil pay.

J / Sturgis

- 25% working interest in Atwater Valley 183.
- Located offshore Louisiana in 3,700' of water.
- Target formation: Miocene sands.
- Discovery well drilled in 2003 encountered > 100' of net oil pay.
- Development potential would be enhanced by success at Sturgis North.

2006 Activity

- Drilled discovery well at Mission Deep.
- Initiated drilling of sidetrack appraisal well at Mission Deep.

2007 Plans

- Complete drilling sidetrack appraisal well at Mission Deep.
- Evaluate development options.

Deepwater Exploration Prospects

Profile

K / Lower Tertiary Prospect #1

- Located in Keathley Canyon area.
- Located offshore Louisiana in 6,000' of water.
- Target formation: Lower Tertiary sands.

L / Lower Tertiary Prospect #2

- Located in Walker Ridge area.
- Located offshore Louisiana in 6,500' of water.
- Target formation: Lower Tertiary sands.

2006 Activity

- Conducted technical evaluations and initiated drilling contracts.

2007 Plans

- Finalize technical evaluations and contracts.
- Drill exploratory test wells.

CANADA

A / Mackenzie Delta/Beaufort Sea

Profile

- 43% average working interest in 2.1 million exploratory acres in the Mackenzie Delta and shallow waters of the Beaufort Sea.
- Devon is the largest holder of exploration acreage in this area.
- Drilling limited to winter only.
- 2002 Tuk M-18 discovery estimated at 200-300 billion cubic feet gross.

2006 Activity

- Drilled and tested Paktoa exploratory well in Beaufort Sea.
- Paktoa well encountered hydrocarbons but did not meet expectations.

2007 Plans

- Apply for Significant Discovery License to retain Paktoa acreage.
- Evaluate potential for future drilling in the Mackenzie Valley corridor.

B / Northeast British Columbia

Profile

- 72% average working interest in 1.7 million acres in northwestern Alberta and northeastern British Columbia.
- Key areas include Hamburg, Peggo, Monias, Ring Border and Wargen.
- Primarily winter-only drilling.
- Produces oil and gas from multiple formations including the Halfway and Baldonnel at 2,600' to 5,000'.
- 59.4 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity
- Drilled 64 wells, including:
  - 20 wells at Wargen.
  - 14 wells at Ring Border.
  - 11 wells at Peggo.
  - 7 wells at Hamburg/Chinchaga.
- Recompleted 12 wells.

2007 Plans
- Drill 68 total wells, including:
  - 26 wells at Wargen.
  - 13 wells at Ring Border.
  - 12 wells at Monias.
  - 7 wells at Hamburg/Chinchaga.

C / Peace River Arch

Profile
- 69% average working interest in 685,000 acres in western Alberta.
- Key areas include Belloy, Cecil, Dunvegan, Eaglesham, Knopcik, Tangent and Valhalla.
- Produces liquids-rich gas and light gravity oil from multiple formations at 4,500' to 8,000'.
- 74.8 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity
- Drilled 82 wells, including:
  - 16 wells at Dunvegan.
  - 16 wells at Valhalla.
  - 12 wells at Cecil.
  - 9 wells at Belloy.
  - 6 wells at Knopcik.
- Recompleted 34 wells.

2007 Plans
- Drill 62 total wells, including:
  - 13 wells at Dunvegan.
  - 10 wells at Cecil.
  - 9 wells at Tangent.
  - 7 wells at Belloy.

D / Deep Basin

Profile
- 46% average working interest in 1.4 million acres in western Alberta and eastern British Columbia.
- Key areas include Bilbo/Cutbank, Hiding, Pinto/Leland and Wapiti/Elmworth.
- Produces liquids rich gas from primarily Cretaceous formations at 2,500' to 14,000'.
- 96.7 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity
- Drilled 115 wells, including:
  - 57 wells at Wapiti/Elmworth.
  - 23 wells at Bilbo/Cutbank.
  - 21 wells at Pinto/Leland.
  - 11 wells at Hiding.
- Recompleted 36 wells.

2007 Plans
- Drill 57 total wells, including:
  - 18 wells at Wapiti/Elmworth.
  - 16 wells at Pinto/Leland.
  - 12 wells at Hiding.
  - 11 wells at Bilbo/Cutbank.

E / Lloydminster

Profile
- 97% working interest in 2.2 million acres in eastern Alberta and Saskatchewan.
- Key areas include End Lake, Iron River, Lloydminster and Manatokan.
- Produces primarily conventional, cold flow heavy oil from multiple formations at 1,000' to 2,300'.
- 84.5 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity
- Drilled 397 wells, including:
  - 198 wells at Iron River.
  - 72 wells at Lloydminster.
  - 70 wells at Manatokan.
  - 46 wells at End Lake.
- Recompleted 126 wells.
- Received downspacing approval for Iron River.

2007 Plans
- Drill 395 total wells, including:
  - 185 wells at Iron River.
  - 82 wells at Manatokan.
  - 53 wells at End Lake.
  - 51 wells at Lloydminster.
- Add additional processing capacity at Manatokan plant.

F / Thermal Heavy Oil

Profile
- 97% average working interest in 82,000 acres in eastern Alberta oil sands.
- Key asset is Jackfish (100% interest).
- Steam-Assisted Gravity Drainage (SAGD) is the primary recovery method.
- Expect to reach 35,000 barrels per day from Jackfish in 2008.
- 186.2 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity
- Drilled 19 horizontal well pairs at Jackfish.
- Continued construction on Jackfish facilities.
- Submitted application for regulatory approval for Jackfish 2.
- Drilled 35 stratigraphic wells to further evaluate Jackfish area potential.
- Continued construction of Access Pipeline to and from Edmonton.

2007 Plans
- Complete facilities construction and initiate steam injection at Jackfish.
- Complete construction of Access Pipeline.
- Continue engineering analysis for Jackfish 2.
- Drill up to 50 stratigraphic wells to further evaluate Jackfish area potential.

INTERNATIONAL

A / Azerbaijan – ACG

Profile
- 5.6% interest in 107,000 acres in the Azeri-Chirag-Gunashli (ACG) oil fields offshore Azerbaijan.
- Initial position obtained in 1999 merger.
- Major oil export pipeline commenced operations in 2006.
- Expect >30,000 barrels per day net to Devon in 2007.
- 83.8 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity
- Drilled and completed 3 wells from the Central Azeri platform.
- Completed 2 pre-drilled wells and drilled and completed 3 additional wells from the West Azeri platform.
- Commenced production from the West Azeri platform.
- Completed 3 pre-drilled wells and commenced production from the East Azeri platform.
- Drilled and completed 1 well from the Chirag platform.
- Pre-drilled 4 wells for future production in the deepwater Gunashli area.
- Completed fabrication of deepwater Gunashli jacket and production facilities.

2007 Plans
- Drill 1 producing well from the Central Azeri platform.
- Drill 3 producing wells from the West Azeri platform.
- Complete 4 pre-drilled wells from the East Azeri platform.
- Sidetrack 1 producing well from the Chirag platform.
- Pre-drill 4 wells and begin completion operations in the deepwater Gunashli area.
- Install platforms and production facilities in the deepwater Gunashli area.

B / Brazil

Profile
- 1.4 million acres in 9 licensed blocks offshore Brazil:
  - Block BM-C-8; 60% interest.
  - Block BC-2; 17.65% interest.
  - Block BM-BAR-3; 100% interest.
  - Block BM-C-30; 25% interest.
  - Block BM-C-32; 40% interest.
  - Block BM-C-34 (C-M-471); 50% interest.
  - Block BM-C-34 (C-M-473); 50% interest.
  - Block BM-C-35; 35% interest.
  - Block BM-CAL-13; 100% interest.
- Located in the Campos, Barreirinhas and Camamu Basins in water depths ranging from 330' to 9,100'.
- Target oil formations at 7,000' to 16,000'.
- Developing 2004 discovery on block BM-C-8 (Polvo development).
- 9.0 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity
- Completed fabrication and installation of platform and production facilities at Polvo.
- Continued Polvo FPSO conversion.
- Initiated drilling a 3-well exploration program on block BM-C-8.
- Drilled 1 unsuccessful exploratory well on block BM-C-30.
- Drilled 1 unsuccessful exploratory well on block BM-C-32.
- Acquired offshore blocks BM-C-34, BM-C-35 and BM-CAL-13.
- Acquired 3-D seismic on BM-CAL-13.

2007 Plans
- Complete platform hook-up and commissioning operations at Polvo.
- Complete conversion, installation and commissioning of Polvo FPSO.
- Drill 9 development wells at Polvo.
- Commence first production in mid-2007 at Polvo.
- Complete exploration drilling on block BM-C-8.
- Reprocess 3-D seismic on blocks BM-C-30, BM-C-32, BM-C-34 and BM-C-35.
- Farmout partial interests to industry partners on block BM-BAR-3 and BM-CAL-13.
- Conduct electromagnetic survey on BM-BAR-3.
- Drill 1 exploratory well on block BC-2.

C / China

Profile
- 4.4 million acres in 3 licensed blocks offshore China:
  - Block 15/34 (Panyu); 24.5% interest.
  - Block 42/05; 100% interest.
  - Block 11/34; 100% interest.
- Located in the South China Sea and Yellow Sea in water depths ranging from 100' to 4,900'.
- Panyu fields produce oil from 1998 and 1999 discoveries.
- 16.8 million barrels of oil equivalent reserves at 12/31/06.

2006 Activity
- Drilled and completed 6 development wells at Panyu.
- Initiated drilling 1 extended reach development well at Panyu.
- Completed installation of water handling facilities on both platforms at Panyu.
- Acquired Yellow Sea block 11/34.
- Acquired 2-D seismic on block 11/34.
- Acquired 3-D seismic on block 42/05.
- Signed contracts to acquire 2 additional exploration blocks in the South China Sea.

2007 Plans
- Complete extended reach development drilling initiated in 2006 at Panyu.
- Drill 7 development wells at Panyu.
- Finalize acquisition of blocks 53/30 and 64/18.
- Acquire 3-D seismic on blocks 53/30 and 64/18.
- Prepare for 2008 drilling on blocks 42/05 and 11/34.

full

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Gerald Thomas
Janice Thomas
Krista Thomas
Mike Thomas
Scott Thomas
Terry Thomas
Tol Thomas
William Thomas
Willie Thomas
Markus Thomerson
Alberta Thompson
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Nancy Thompson
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Lynn Thomson
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Melva Thornton
Todd Thorpe
Gary Thrasher
Jill Thrush
Cecil Thurmond
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Shivi Thusoo
Terry Tibble
Jason Tiller
Paula Timm
Allen Timmons
Secily Tincher
Armstrong Ting
Loyd Tinsley
Matt Tisdale
Pat Tisdale
Sandra Tizzard
Katalin Todea
Robert Todor
Janice Toldan
Eldon Tolle
Barbara Tomaja
Ralph Tomlinson
Gregg Tompkins
Pamela Tongsrinark
Ron Tonne
Mike Toole
Vincent Topacio
Bonnie Toporowski
Erin Toporowski
Bill Torguson
Reah Torres
David Touchet
Muriel Tourangeau
Nicole Towers
Jason Townsend
Ricky Townsend
Tanya Townsend
Robert Tracy
Roddy Trahan
Ronald Trahan
Jake Trainer
Seila Tran
Kirk Trascher
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Lynn Travis
Nicole Tremblay
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Belinda Trevino
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Howard Trinh
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Howie Truong
Mladen Trzok
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Kerry Tufford
Cory Tuffs
Vance Turman
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Mike Turner
Judi Twiggs
Nick Twist
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Bruce Tyler
Kyle Tyson
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Lorraine Urbani
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John Vandeligt
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Thomas VandeReep
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Renier VanRensburg
Gerald vanRiet
Hector VanVierssen Trip
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Ramaswami Vasudevan
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Elaina Venechuk
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Raymond Veraart
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Patti Verhille
Adrienne Verkler
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Dexter Vidrine
Phillip Vidrine
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Stephanie Vilaros
Alejandra Villalobo
Juanita Villalon
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JR Villarreal
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Virginia Villarreal
Maggie Villatoro
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Nathan Vincent
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Esther Wagner
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Pat Wagner
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Janice Wagoner
Kevin Wagoner
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Danielle Walcher
Ken Wald
Joseph Waldner
Ira Waldron
Patrick Waldron

Aimee Walker
David Walker
Debra Walker
Glynn Walker
John Walker
John Walker
Kenneth Walker
Kim Walker
Larry Walker
Linda Walker
Melissa Walker
Michelle Walker
Paul Walker
Richard Walker
Peggy WalkingStick
Kenneth Walko
Don Wall
Deborah Wallace
Hollis Wallace
Scott Wallace
Michael Walle
Joan Waller
Frank Walles
Bill Walter
Colette Walter
Gina Walters
Eric Wampler
Owen Wampler
Jack Wang
Peter Wang
Rock Wang
Tony Wang
Xia Qing Wang
George Wanke
Nick Warburton
Bill Ward
Doug Ward
Evelyn Ward
Lloyd Ward
Wade Wardlow
Douglas Ware
Colleen Warrellow
William Warren
Win Warren
Kristen Wascom
Brian Washburn
Clarence Washington
Faye Ruffin Washington
Len Watchorn
Michelle Waterfield
Caleb Watkins
Calvin Watson
Gary Watson
Kevin Watson
Lynne Watson
Ron Watson
Tashila Watson
Tony Watson
Marg Watt
Shad Watts
Bobby Watzil
Murray Weatherhead
Ed Weatherly
Don Webb
Glyn Webb
Kris Webb
Sharon Webb
Paul Weber
Stan Weed
Allan Wehe
Joah Weidemann
Bret Weigel
Greg Weild
Jonathan Weir
Ryan Weisbrot
Jeffrey Weiss
Myles Weiss
Alisa Welch
Brook Welch
Diana Welch
Geoff Welch
Joe Weldon
Miles Welke
Carol Wells
Merla Wells
Wallace Wells
Yuan Wendy Wen
Steven Wendte
Beverly Wenzel
Lacey Wenzel
Rusty Werline
Herbert Werner
Daniel Werth
Bill Wescott
Blake West
Michelle West
Timothy West
Raymond Westbrook
Adam Westlake
Michelle Weston
Troy Wharton
Wendy Wharton
Amanda Wheat
Ian Wheatley
Bill Wheaton
Natalie Wheeler
Robert Wheeler
Gaylynn Wheelis
Linda Whelan
Peter Whelan
Sara Whelen
Cathy Whicker
Alan White
Brian White
Jennifer White
Jim White
John White
Lisa White
Marilynn White
Mike White
Mike White
Richard White
Roy White
Stephanie White
Vince White
Jimmy Whitehead
Marcus Whitehead
Paul Whitehead
Douglas Whiteside

Brad Whitley
Robert Whitley
Ryan Whitlow
Lu'ana Whitmarsh
Kelly Whitney
Monte Whitt
Greg Whyte
Jenifer Wick
Rebecca Wicke
Bruce Wiebe
Paul Wiebe
Chris Wiggers
Krista Wiggins
Jim Wigley
Alyssa Wilburn
Denise Wilders
Mike Wilders
Shannon Wiley
Jason Wilhelm
Sena Wilke
Anthony Wilkerson
Kim Wilkerson
Calvin Wilkin
Craig Wilkins
Lynne Wilkins
Scott Wilkins
Selwyn Wilkinson
Steve Wilkinson
Robert Will
Clark Willard
Austin Williams
Bonnie Williams
Brett Williams
Brian Williams
Christopher Williams
Dean Williams
Deborah Williams
Don Williams
Frank Williams
H. Russell Williams
Jeffrey Williams
Kathy Williams
Laura Williams
Lonetta Williams
Lynn Williams
Mark Williams
Michael Williams
Roger Williams
Sandie Williams
Stephanie Williams
Steve Williams
Wanda Williams
Helen Williamson
James Williamson
Norman Williamson
Jeff Williford
Larry Willis
Bryan Willmon
Darlene Willoughby
Matt Willrath
Mark Willstrop
Ken Wilpitz
Bill Wilsey
Alister Wilson
Ben Wilson
Brent Wilson
Corey Wilson
Dennis Wilson
Don Wilson
Gwen Wilson
Jacqueline Wilson
James Wilson
Karla Wilson
Kerri Wilson
Meridith Wilson
Patti Wilson
Paul Wilson
Rebecca Wilson
Sherry Wilson
Stafford Wilson
Tawny Wilson
Tom Wilson
Yakini Wilson
Nick Wiltgen
William Wimberg
Wendy Wingerter
James Wingo
Jason Winia
James Winkleman
Becky Winkler
Virginia Winn
Scott Winter
Sandra Winzig
Criston Wise-Kennedye
Kristi Wisely
Marsha Wiseman
Vanessa Wisnoski
Gene Wissinger
Robert Witherspoon
Brandi Withrow
Ken Wolfe
Mike Wolfe
Shonna Wolfe
Troy Wolfe
Wayne Wolfe
Jim Wolz
Phillip Womack
Ron Womack
Tanner Womack
Henry Wong
Jorge Wong
Julie Wong
Kenneth Wong
Christopher Woo
Colin Wood
Daniel Wood
Geoff Wood
Grant Wood
Grant Wood
Jeri Wood
Joseph Wood
Steven Wood
Terianne Wood
Wendell Wood
Brian Woodard
Craig Woodard
Kevin Woodard
Charlotte Woods
Mark Woods

Ted Woods
Nicole Woodson
Dee Woolam
Jan Wooldridge
Michael Wooldridge
Courtney Wooten
Ralph Wooton
Tim Word
Chad Workman
Robert Workman
Tom Worley
Charlie Wright
Gregory Wright
Katherine Wright
Kelvin Wright
Mandy Wright
Mary Wright
Robert Wright
Layne Wroblewski
Hody Wu
Xian Wu
Brandon Wuttunee-Campbell
Vicky Wyalie
Norm Wyffels
Everett Wylie
Robert Wyness
Joseph Wyszynski
Hongdi Xu
Clinton Yaeger
Calvin Yakel
Christy Yakel
William Yakymyshyn
Gerald Yamada
Jackie Yard
Ken Yaremko
Larry Yasman
Lori Yates
Jonathan Yee
Michael Yeh
Donald Yep
Michael Yester
Robert Yother
Angelica Young
Burt Young
Carla Young
Dennis Young
Eileen Young
Linda Young
Terri Young
Tim Young
Tony Young
Trevor Young
Vern Young
Jerry Youngblood
Lorre Youngblood
Bryan Younger
Stephanie Ysasaga
Francis Yu
Jenny Yu
Randy Yuristy
Doug Yuzwenko
Johnny Zachary
Bruce Zagoruy
Garnet Zarowny
Leandra Zarowny
Kim Zauderer
Sean Zawada
Robert Zehr
Mark Zesko
James Zeuch
Brian Ziemmer
Chris Zimbelman
Larry Zimbelman
Harold Zimmerman
Clifford Zinger
Steve Zink
Camilo Zoleta
Tatiana Zouenko
James Zuk
Rudy Zuniga
Dino Zuzic
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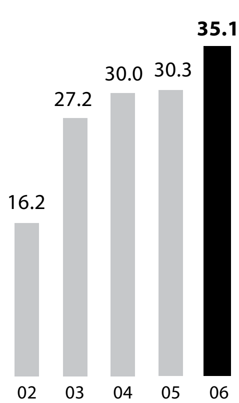
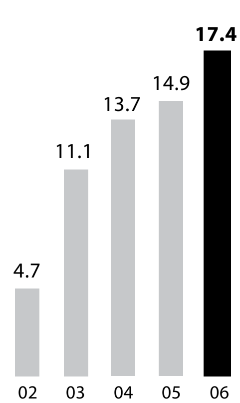
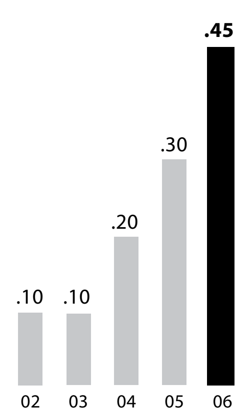
TOTAL ASSETS
($ Billions)



STOCKHOLDERS' EQUITY
($ Billions)



DIVIDEND RATE
($ Per Common Share)



Over the past five years Devon has more than doubled total assets to $35.1 billion and more than tripled stockholders' equity to $17.4 billion. During this same period the company has increased its dividend more than four fold to $0.45 per common share in 2006.

Selected Eleven-Year Financial Data (1)

		1996	1997	1998	1999
Operating Results *(In millions, except per share data)*					
Revenues (Net of royalties):					
Oil sales	$	529	497	236	436
Gas sales		211	367	335	616
NGL sales		29	36	25	68
Marketing and midstream revenues		—	10	8	20
Other income		36	36	6	23
Total revenues		805	946	610	1,163
Production and operating expenses		271	288	231	328
Marketing and midstream costs and expenses		—	4	3	10
Depreciation, depletion and amortization of property and equipment		175	268	212	379
Accretion of asset retirement obligation		—	—	—	—
Amortization of goodwill (2)		—	—	—	16
General and administrative expenses		57	56	48	83
Expenses related to mergers		—	—	13	17
Interest expense		59	51	53	122
Change in fair value of financial instruments		—	—	—	—
Reduction of carrying value of oil and gas properties		—	633	354	476
Impairment of Chevron Corporation common stock		—	—	—	—
Income tax expense (benefit)		106	(128)	(103)	(75)
Total expenses		668	1,172	811	1,356
Net earnings (loss) before minority interest, cumulative effect of change in accounting principle and discontinued operations (3)		137	(226)	(201)	(193)
Net earnings (loss)		151	(218)	(236)	(154)
Preferred stock dividends		47	12	—	4
Net earnings (loss) to common stockholders	$	104	(230)	(236)	(158)
Net earnings (loss) per common share:					
Basic	$	0.98	(1.67)	(1.66)	(0.84)
Diluted	$	0.96	(1.67)	(1.66)	(0.84)
Weighted average shares outstanding:					
Basic		105	137	142	187
Diluted		111	151	154	199
Balance Sheet Data *(In millions)*					
Total assets	$	2,242	1,965	1,931	6,096
Debentures exchangeable into shares of Chevron Corporation common stock (4)	$	—	—	—	760
Other long-term debt	$	511	576	885	1,656
Deferred income taxes	$	136	50	15	313
Stockholders' equity	$	1,160	1,006	750	2,521
Common shares outstanding		126	142	142	253

(1) The years 1996 to 2002 exclude results from Devon's operations in Indonesia, Argentina and Egypt that were discontinued in 2002. Devon acquired new assets in Egypt in the April 2003 Ocean merger. The years 2003 through 2006 exclude results from operations in Egypt that were discontinued in 2006. Data has been restated to reflect the 1998 merger of Devon and Northstar and the 2000 merger of Devon and Santa Fe Snyder in accordance with the pooling-of-interests method of accounting. All periods prior to the November 15, 2004 two-for-one stock split have been adjusted to reflect the split.

(2) Amortization of goodwill in 1999, 2000 and 2001 resulted from Devon's 1999 acquisition of PennzEnergy. As of January 1, 2002, goodwill is no longer amortized.

(3) Before minority interest in Monterrey Resources, Inc. of ($1) and ($5) million in 1996 and 1997, respectively, and the cumulative effect of change in accounting principle of $49 and $16 million in 2001 and 2003, respectively, and the results of discontinued operations of $15, $13, ($35) $39, $69, $31, $45, ($31), $5, $31 and $23 million in 1996 through 2006, respectively.

(4) Devon beneficially owns 14.2 million shares of Chevron Corporation common stock. These shares have been deposited with an exchange agent for possible exchange for $760 million principal amount of exchangeable debentures. The Chevron shares and debentures were acquired through the 1999 acquisition of PennzEnergy.

N/M Not a meaningful number.

2000	2001	2002	2003	2004	2005	2006	5-YEAR COMPOUND GROWTH RATE	10-YEAR COMPOUND GROWTH RATE
906	784	909	1,545	2,099	2,359	3,205	33%	20%
1,474	1,878	2,133	3,896	4,732	5,784	4,932	21%	37%
154	131	275	407	554	687	749	42%	39%
53	71	999	1,461	1,701	1,792	1,692	89%	N/M
37	58	35	106	126	198	115	15%	12%
2,624	2,922	4,321	7,415	9,212	10,820	10,693	30%	30%
544	666	886	1,274	1,514	1,659	1,829	22%	21%
28	47	808	1,174	1,339	1,342	1,244	93%	N/M
662	831	1,211	1,761	2,225	2,141	2,442	24%	30%
—	—	—	36	44	43	49	N/M	N/M
41	34	—	—	—	—	—	N/M	N/M
96	114	219	307	277	291	397	28%	21%
60	1	—	7	—	—	—	N/M	N/M
155	220	533	502	475	533	421	14%	22%
—	2	(28)	(1)	62	94	178	145%	N/M
—	979	651	66	—	212	121	-34%	N/M
—	—	205	—	—	—	—	N/M	N/M
377	5	(193)	527	1,095	1,606	1,189	199%	27%
1,963	2,899	4,292	5,653	7,031	7,921	7,870	22%	28%
661	23	59	1,762	2,181	2,899	2,823	162%	35%
730	103	104	1,747	2,186	2,930	2,846	94%	34%
10	10	10	10	10	10	10	0%	-14%
720	93	94	1,737	2,176	2,920	2,836	98%	39%
2.83	0.37	0.31	4.16	4.51	6.38	6.42	77%	21%
2.75	0.36	0.30	4.04	4.38	6.26	6.34	77%	21%
255	255	309	417	482	458	442	12%	15%
263	259	313	433	499	470	448	12%	15%
6,860	13,184	16,225	27,162	30,025	30,273	35,063	22%	32%
760	649	662	677	692	709	727	2%	N/M
1,289	5,940	6,900	7,903	6,339	5,248	4,841	-4%	25%
634	2,149	2,627	4,315	4,764	5,374	5,650	21%	45%
3,277	3,259	4,653	11,056	13,674	14,862	17,442	40%	31%
257	252	314	472	484	443	444	12%	13%

Management's Discussion and Analysis of Financial Condition and Results of Operations

OVERVIEW OF 2006 RESULTS AND OUTLOOK

2006 was one of the best years in Devon's history. We achieved key operational successes and continued to execute our strategy to increase value per share. As a result, we delivered record amounts for earnings per share and operating cash flow and grew proved reserves to a new all-time high. Key measures of our financial and operating performance for 2006, as well as certain operational developments, are summarized below:

- Net earnings declined 3% from $2.9 billion to $2.8 billion
- Diluted net earnings per share increased 1% to $6.34 per diluted share
- Net cash provided by operating activities reached $6.0 billion
- Estimated proved reserves at December 31, 2006 reached a record amount of 2.4 billion Boe
- Estimated proved reserves increased 533 million Boe through drilling, extensions, performance revisions and acquisitions
- Capital expenditures for oil and gas exploration and development activities were $7.7 billion, including the $2.2 billion acquisition of Chief
- Combined realized price for oil, gas and NGLs per Boe increased 5% to $41.51
- Marketing and midstream operating profit remained flat at $448 million for 2006

We produced 214 million Boe in 2006, representing a 4% decrease compared to 2005. Excluding the effects of production lost due to the sale of non-core properties in the first half of 2005, our year-over-year production remained constant. Operating costs increased due to inflationary pressure driven by the effects of higher commodity prices and due to the weakened U.S. dollar compared to the Canadian dollar. Per unit lease operating expenses increased 17% to $6.95 per Boe.

During 2006, we utilized cash on hand, cash flow from operations, and $1.8 billion of commercial paper borrowings to fund our capital expenditures, repay $862 million in debt and repurchase $253 million of our common stock. We ended the year with $1.3 billion of cash and short-term investments.

From an operational perspective, our deepwater Gulf of Mexico exploration program has reached several important milestones related to the Lower Tertiary trend. To date, we have drilled four discovery wells in the Lower Tertiary—Cascade in 2002, St. Malo in 2003, Jack in 2004 and Kaskida in the third quarter of 2006. Also in the third quarter of 2006, we announced the successful production test of the Jack No. 2 well in the Lower Tertiary. We currently hold 273 blocks in the Lower Tertiary and have identified 19 additional exploratory prospects within these blocks to date. These achievements support our positive view of the Lower Tertiary and demonstrate the growth potential of our high-impact exploration strategy on long-term production, reserves and value.

On June 29, 2006, we acquired Chief's oil and gas assets located in the Barnett Shale area of Texas for $2.2 billion. This transaction added 99.7 million Boe of proved reserves and 169,000 net acres to our Barnett Shale assets. This acquisition combined with our organic growth continues to extend our leadership position in the Barnett Shale and provides years of additional drilling inventory.

On November 14, 2006, we announced our plans to divest our operations in Egypt. At December 31, 2006, Egypt had proved reserves of eight million Boe. Subsequently, on January 23, 2007, we announced our plans to divest our operations in West Africa, including Equatorial Guinea, Cote d'Ivoire, and other countries in the region. At December 31, 2006, our West Africa operations had proved reserves of 90 million Boe, or 4% of total proved reserves. We anticipate completing the sale of our Egyptian assets in the first half of 2007 and our West African assets in the third quarter of 2007. Divesting these properties will allow us to redeploy our financial and intellectual capital to the significant growth opportunities we have developed onshore in North America and in the deepwater Gulf of Mexico. Additionally, we will sharpen our focus in North America and concentrate our international operations in Brazil and China, where we have established competitive advantages.

Looking to 2007, we intend to use the proceeds from the sales of our operations in Egypt and West Africa to repay our outstanding commercial paper and resume common stock repurchases. In addition, our operational accomplishments to date have laid the foundation for continued growth in future years, at competitive unit costs, that we expect will continue to create additional value for our investors. In 2007, we expect to deliver reserve additions of 350 to 370 million Boe with related capital expenditures in the range of $5.3 to $5.7 billion. We expect production related to our continuing operations to increase approximately 10% from 2006 to 2007, which reflects the significant reserve additions in 2005 and 2006, and those expected in 2007.

RESULTS OF OPERATIONS

Revenues

Changes in oil, gas and NGL production, prices and revenues from 2004 to 2006 are shown in the following tables. The amounts for all periods presented exclude our Egyptian operations. Unless otherwise stated, all dollar amounts are expressed in U.S. dollars.

TOTAL — YEAR ENDED DECEMBER 31,		2006	2006 vs 2005 (2)	2005	2005 vs 2004 (2)	2004
PRODUCTION						
Oil (MMBbls)		55	-11%	62	-17%	74
Gas (Bcf)		815	-1%	827	-7%	891
NGLs (MMBbls)		23	-2%	24	-1%	24
Oil, gas and NGLs (MMBoe)(1)		214	-4%	224	-9%	247
AVERAGE PRICES						
Oil (per Bbl)	$	58.30	+53%	38.00	+35%	28.22
Gas (per Mcf)	$	6.06	-13%	6.99	+32%	5.32
NGLs (per Bbl)	$	32.10	+11%	28.96	+26%	23.04
Oil, gas and NGLs (per Boe)(1)	$	41.51	+5%	39.48	+32%	29.92
REVENUES (in millions)						
Oil	$	3,205	+36%	2,359	+12%	2,099
Gas		4,932	-15%	5,784	+22%	4,732
NGLs		749	+9%	687	+24%	554
Oil, gas and NGLs	$	8,886	+1%	8,830	+20%	7,385

DOMESTIC — YEAR ENDED DECEMBER 31,		2006	2006 vs 2005 (2)	2005	2005 vs 2004 (2)	2004
PRODUCTION						
Oil (MMBbls)		19	-23%	25	-19%	31
Gas (Bcf)		566	+2%	555	-8%	602
NGLs (MMBbls)		19	+3%	18	-4%	19
Oil, gas and NGLs (MMBoe)(1)		132	-3%	136	-10%	151
AVERAGE PRICES						
Oil (per Bbl)	$	62.23	+49%	41.64	+35%	30.84
Gas (per Mcf)	$	6.09	-14%	7.08	+30%	5.43
NGLs (per Bbl)	$	29.42	+10%	26.68	+24%	21.47
Oil, gas and NGLs (per Boe)(1)	$	39.31	-2%	40.21	+31%	30.80
REVENUES (in millions)						
Oil	$	1,218	+15%	1,062	+9%	976
Gas		3,445	-12%	3,929	+20%	3,261
NGLs		548	+13%	484	+19%	405
Oil, gas and NGLs	$	5,211	-5%	5,475	+18%	4,642

CANADA — YEAR ENDED DECEMBER 31,		2006	2006 vs 2005 (2)	2005	2005 vs 2004 (2)	2004
PRODUCTION						
Oil (MMBbls)		13	-2%	13	-5%	14
Gas (Bcf)		241	-8%	261	-6%	279
NGLs (MMBbls)		4	-11%	6	+8%	5
Oil, gas and NGLs (MMBoe)(1)		58	-7%	62	-5%	65
AVERAGE PRICES						
Oil (per Bbl)	$	46.94	+75%	26.88	+24%	21.60
Gas (per Mcf)	$	6.05	-13%	6.95	+35%	5.15
NGLs (per Bbl)	$	42.67	+15%	37.19	+27%	29.23
Oil, gas and NGLs (per Boe)(1)	$	39.21	+3%	38.17	+33%	28.80
REVENUES (in millions)						
Oil	$	603	+71%	353	+18%	299
Gas		1,456	-20%	1,814	+26%	1,437
NGLs		201	+2%	196	+38%	143
Oil, gas and NGLs	$	2,260	-4%	2,363	+26%	1,879

	INTERNATIONAL YEAR ENDED DECEMBER 31,					
		2006	2006 vs 2005 (2)	2005	2005 vs 2004 (2)	2004
PRODUCTION						
Oil (MMBbls)		23	-4%	24	-19%	29
Gas (Bcf)		8	-25%	11	+6%	10
NGLs (MMBbls)		—	N/M	—	N/M	—
Oil, gas and NGLs (MMBoe)(1)		24	-7%	26	-17%	31
AVERAGE PRICES						
Oil (per Bbl)	$	61.36	+52%	40.26	+41%	28.53
Gas (per Mcf)	$	3.95	+5%	3.75	+13%	3.33
NGLs (per Bbl)	$	—	N/M	22.81	+8%	21.12
Oil, gas and NGLs (per Boe)(1)	$	59.24	+53%	38.80	+39%	27.99
REVENUES (in millions)						
Oil	$	1,384	+47%	944	+15%	824
Gas		31	-21%	41	+20%	34
NGLs		—	N/M	7	+12%	6
Oil, gas and NGLs	$	1,415	+43%	992	+15%	864

(1) Gas volumes are converted to Boe or MMBoe at the rate of six Mcf of gas per barrel of oil, based upon the approximate relative energy content of natural gas and oil, which rate is not necessarily indicative of the relationship of oil and gas prices. NGL volumes are converted to Boe on a one-to-one basis with oil.
(2) All percentage changes included in this table are based on actual figures and not the rounded figures included in this table.
N/M Not meaningful.

The average prices shown in the preceding tables include the effect of our oil and gas price hedging activities. Following is a comparison of our average prices with and without the effect of hedges for each of the last three years.

		WITH HEDGES			WITHOUT HEDGES		
		2006	2005	2004	2006	2005	2004
Oil (per Bbl)	$	58.30	38.00	28.22	58.30	48.43	36.02
Gas (per Mcf)	$	6.06	6.99	5.32	6.01	7.04	5.34
NGLs (per Bbl)	$	32.10	28.96	23.04	32.10	28.96	23.04
Oil, gas and NGLs (per Boe)	$	41.51	39.48	29.92	41.34	42.55	32.37

The following table details the effects of changes in volumes and prices on our oil, gas and NGL revenues between 2004 and 2006.

		OIL	GAS	NGL	TOTAL
			(IN MILLIONS)		
2004 REVENUES	$	2,099	4,732	554	7,385
Changes due to volumes		(347)	(337)	(8)	(692)
Changes due to prices		607	1,389	141	2,137
2005 REVENUES		2,359	5,784	687	8,830
Changes due to volumes		(270)	(86)	(11)	(367)
Changes due to prices		1,116	(766)	73	423
2006 REVENUES	$	3,205	4,932	749	8,886

Oil Revenues

2006 vs. 2005 Oil revenues decreased $270 million due to a seven million barrel decrease in production. Production lost from properties divested in 2005 accounted for four million barrels of the decrease. A contractual reduction of our share of production from one of our international properties in mid-2005 also lowered 2006 volumes. These decreases were partially offset by a three million barrel increase in production resulting from reaching payout of certain carried interests in Azerbaijan.

Oil revenues increased $1.1 billion as a result of a 53% increase in our realized price. The expiration of oil hedges at the end of 2005 and a 17% increase in the average NYMEX West Texas Intermediate index price caused the increase in our realized oil price.

2005 vs. 2004 Oil revenues decreased $347 million due to a 12 million barrel decrease in production. Production lost from the 2005 property divestitures accounted for seven million barrels of the decrease. We also suspended certain domestic production in 2005 and 2004 due to the effects of Hurricanes Katrina, Rita, Dennis and Ivan. The volumes suspended in 2005 were one million barrels more than in 2004. The remainder of the decrease is due to certain international properties in which our ownership interest decreased after we recovered our costs under the applicable production sharing contracts.

Higher realized prices caused oil revenues to increase $607 million in 2005. Our 2005 oil prices rose primarily due to a 37% increase in the average NYMEX West Texas Intermediate index price.

Gas Revenues

2006 vs. 2005 A 12 Bcf decrease in production caused gas revenues to decrease by $86 million. Production lost from the 2005 property divestitures caused a decrease of 35 Bcf. As a result of the previously mentioned hurricanes, gas volumes suspended in 2006 were three Bcf more than those suspended in 2005. These decreases were partially offset by the June 2006 Chief acquisition, which contributed 10 Bcf of production during the last half of 2006, and additional production from new drilling and development in our U.S. onshore and offshore properties.

A 13% decline in average prices caused gas revenues to decrease $766 million in 2006.

2005 vs. 2004 A 64 Bcf decrease in production caused gas revenues to decrease by $337 million. Production associated with the 2005 property divestitures caused a decrease of 89 Bcf. We also suspended certain domestic gas production in 2005 and 2004 due to the previously mentioned hurricanes. The volumes suspended in 2005 were 12 Bcf more than in 2004. These decreases were partially offset by new drilling and development and increased performance in U.S. onshore and offshore properties.

A 32% increase in average gas prices contributed $1.4 billion of additional revenues in 2005.

Marketing and Midstream Revenues and Operating Costs and Expenses

The following table details the changes in our marketing and midstream revenues and operating costs and expenses between 2004 and 2006. The changes due to prices in the table represent the net effect on both revenues and expenses due to changes in the market prices for natural gas and NGLs.

		REVENUES	EXPENSES
		(IN MILLIONS)	
2004 MARKETING & MIDSTREAM	$	1,701	1,339
Changes due to volumes		(351)	(303)
Changes due to prices		442	306
2005 MARKETING & MIDSTREAM		1,792	1,342
Changes due to volumes		159	117
Changes due to prices		(259)	(215)
2006 MARKETING & MIDSTREAM	$	1,692	1,244

2006 vs. 2005 Volume increases in our gas pipeline, gas sales and NGL marketing activities caused both revenues and expenses to increase in 2006. This additional activity was primarily due to our continued growth in the Barnett Shale and higher natural gas deliveries from third-party producers

2005 vs. 2004 Volume decreases in 2005 caused both revenues and expenses to decline in 2005. The lower activity was primarily attributable to the sale of certain non-core assets in 2004 and 2005.

Oil, Gas and NGL Production and Operating Expenses

The details of the changes in oil, gas and NGL production and operating expenses between 2004 and 2006 are shown in the table below.

		YEAR ENDED DECEMBER 31,				
		2006	2006 vs 2005 (1)	2005	2005 vs 2004 (1)	2004
PRODUCTION AND OPERATING EXPENSES (in millions):						
Lease operating expenses	$	1,488	+12%	1,324	+ 5%	1,259
Production taxes		341	+ 2%	335	+31%	255
Total production and operating expenses	$	1,829	+10%	1,659	+10%	1,514
PRODUCTION AND OPERATING EXPENSES PER BOE:						
Lease operating expenses	$	6.95	+17%	5.92	+16%	5.10
Production taxes		1.59	+ 6%	1.50	+46%	1.03
Total production and operating expenses per Boe	$	8.54	+15%	7.42	+21%	6.13

(1) All percentage changes included in this table are based on actual figures and not the rounded figures included in this table.

2006 vs. 2005 Lease operating expenses increased $164 million in 2006 largely due to higher commodity prices. Commodity price increases in 2005 and the first half of 2006 contributed to industry-wide inflationary pressures on materials and personnel costs. Additionally, consideration of higher commodity prices contributed to our decision to perform more well workovers and maintenance projects to maintain or improve production volumes. Commodity price increases also caused operating costs such as ad valorem taxes, power and fuel costs to rise.

A higher Canadian-to-U.S. dollar exchange rate in 2006 caused a $34 million increase in our costs. Lease operating expenses also increased $33 million due to the June 2006 Chief acquisition and the payouts of our carried interests in Azerbaijan in the last half of 2006. The increases in our lease operating expenses were partially offset by a decrease of $82 million related to properties that were sold in 2005.

The factors described above were also the primary factors causing lease operating expenses per Boe to increase during 2006. Although we divested properties in 2005 that had higher per-unit operating costs, the cost escalation largely related to higher commodity prices and the weaker U.S. dollar had a greater effect on our per unit costs than the property divestitures.

2005 vs. 2004 Lease operating expenses increased $65 million in 2005 largely due to higher commodity prices. As addressed above, commodity price increases led to overall industry inflation. Additionally, a higher Canadian-to-U.S. dollar exchange rate in 2005 caused a $30 million increase in 2005. Partially offsetting these increases was a decrease of $144 million in lease operating expenses related to properties that were sold in 2005.

The increases described above were also the primary factors causing lease operating expenses per Boe to increase. Although we divested properties that had higher per-unit operating costs, the cost escalation largely related to higher commodity prices and the weaker U.S. dollar had a greater effect on our per unit costs than the property divestitures.

The following table details the changes in production taxes between 2004 and 2006. The majority of our production taxes are assessed on our onshore domestic properties. In the U.S., most of the production taxes are based on a fixed percentage of revenues. Therefore, the changes due to revenues in the table primarily relate to changes in oil, gas and NGL revenues from our U.S. onshore properties.

	(IN MILLIONS)
2004 PRODUCTION TAXES	$ 255
Change due to revenues	50
Change due to rate	30
2005 PRODUCTION TAXES	335
Change due to revenues	(23)
Change due to rate	29
2006 PRODUCTION TAXES	$ 341

2006 vs. 2005 Production taxes increased $29 million due to an increase in the effective production tax rate in 2006. A new Chinese "Special Petroleum Gain" tax was the primary contributor to the higher rate.

2005 vs. 2004 Production taxes increased $30 million due to an increase in the effective production tax rate in 2005. An increase in Russian export tax rates was the primary contributor to the higher rate.

Depreciation, Depletion and Amortization of Oil and Gas Properties ("DD&A")

DD&A of oil and gas properties is calculated by multiplying the percentage of total proved reserve volumes produced during the year, by the "depletable base." The depletable base represents the net capitalized investment plus future development costs in those reserves. Generally, if reserve volumes are revised up or down, then the DD&A rate per unit of production will change inversely. However, if the depletable base changes, then the DD&A rate moves in the same direction. The per unit DD&A rate is not affected by production volumes. Absolute or total DD&A, as opposed to the rate per unit of production, generally moves in the same direction as production volumes. Oil and gas property DD&A is calculated separately on a country-by-country basis.

The following table details the changes in DD&A of oil and gas properties between 2004 and 2006. The changes due to volumes in the table represent the effect on DD&A due to decreases in combined oil, gas and NGL production.

	(IN MILLIONS)
2004 DD&A	$ 2,077
Change due to volumes	(195)
Change due to rate	99
2005 DD&A	1,981
Change due to volumes	(85)
Change due to rate	370
2006 DD&A	$ 2,266

2006 vs. 2005 Oil and gas property related DD&A increased $370 million in 2006 due to an increase in the DD&A rate from $8.86 per Boe in 2005 to $10.59 per Boe in 2006. The largest contributor to the rate increase was inflationary pressure on both the costs incurred during 2006 as well as the estimated development costs to be spent in future periods on proved undeveloped reserves. Other factors contributing to the rate increase include the June 2006 Chief acquisition and the transfer of previously unproved costs to the depletable base as a result of 2006 drilling activities. A reduction in reserve estimates due to the effects of 2006 year-end commodity prices also contributed to the rate increase.

2005 vs. 2004 Oil and gas property related DD&A increased $99 million in 2005 due to an increase in the DD&A rate from $8.41 per Boe in 2004 to $8.86 per Boe in 2005. The largest contributor to the rate increase was the effect of inflationary pressure on finding and development costs for reserve discoveries and extensions. Changes in the Canadian-to-U.S. dollar exchange rate also caused the rate to increase. These increases were partially offset by a decrease in the rate as a result of our 2005 property divestitures.

General and Administrative Expenses ("G&A")

Our net G&A consists of three primary components. The largest of these components is the gross amount of expenses incurred for personnel costs, office expenses, professional fees and other G&A items. The gross amount of these expenses is partially reduced by two offsetting components. One is the amount of G&A capitalized pursuant to the full cost method of accounting related to exploration and development activities. The other is the amount of G&A reimbursed by working interest owners of properties for which we serve as the operator. These reimbursements are received during both the drilling and operational stages of a property's life. The gross amount of G&A incurred, less the amounts capitalized and reimbursed, is recorded as net G&A in the consolidated statements of operations. Net G&A includes expenses related to oil, gas and NGL exploration and production activities, as well as marketing and midstream activities. See the following table for a summary of G&A expenses by component.

		YEAR ENDED DECEMBER 31,				
		2006	2006 vs 2005	2005	2005 vs 2004	2004
				(IN MILLIONS)		
Gross G&A	$	769	+33%	577	+6%	545
Capitalized G&A		(269)	+49%	(181)	+9%	(166)
Reimbursed G&A		(103)	-2%	(105)	+3%	(102)
Net G&A	$	397	+36%	291	+5%	277

2006 vs. 2005 Gross G&A increased $192 million. Higher employee compensation and benefits costs caused gross G&A to increase $149 million. Of this increase, $34 million represented stock option expense recognized pursuant to our adoption in 2006 of Statement of Financial Accounting Standard No. 123(R), *Share-Based Payment*. An additional $28 million of the increase related to higher restricted stock compensation. In addition, changes in the Canadian-to-U.S. dollar exchange rate caused an $11 million increase in costs.

2005 vs. 2004 Gross G&A increased $32 million. Higher employee compensation and benefits costs caused gross G&A to increase $35 million. Of this increase, $17 million related to higher restricted stock compensation. In addition, changes in the Canadian-to-U.S. dollar exchange rate caused a $9 million increase in costs. These increases were partially offset by an $8 million decrease in rent expense resulting primarily from the abandonment of certain Canadian office space in 2004.

The factors discussed above were also the primary factors that caused the $88 million and $15 million increases in capitalized G&A in 2006 and 2005, respectively.

Interest Expense

The following schedule includes the components of interest expense between 2004 and 2006.

		YEAR ENDED DECEMBER 31,		
		2006	2005	2004
			(IN MILLIONS)	
Interest based on debt outstanding	$	486	507	513
Capitalized interest		(79)	(70)	(70)
Other interest		14	96	32
Total interest expense	$	421	533	475

Interest based on debt outstanding decreased from 2004 to 2006 primarily due to the net effect of debt repayments during 2005 and 2006. This was partially offset by the effect of increased commercial paper borrowings during the last half of 2006 related to the acquisition of the Chief properties.

During 2005, we redeemed our $400 million 6.75% notes due March 15, 2011 and our zero coupon convertible senior debentures prior to their scheduled maturity dates. The other interest category in the table above includes $81 million in 2005 related to these early retirements.

During 2004, we repaid the balance under our $3 billion term loan credit facility prior to the scheduled repayment date. The other interest category in the table above includes $16 million in 2004 related to this early repayment.

Reduction of Carrying Value of Oil and Gas Properties

During 2006 and 2005, we reduced the carrying value of certain of our oil and gas properties due to full cost ceiling limitations and unsuccessful exploratory activities. A detailed description of how full cost ceiling limitations are determined is included in the Critical Accounting Policies and Estimates section of this report. A summary of these reductions and additional discussion is provided below.

	YEAR ENDED DECEMBER 31,			
	2006		2005	
	GROSS	NET OF TAXES	GROSS	NET OF TAXES
	(IN MILLIONS)			
Unsuccessful exploratory reductions:				
Nigeria	$ 85	85	—	—
Brazil	16	16	42	42
Angola	—	—	170	119
Ceiling test reduction – Russia	20	10	—	—
Total	$ 121	111	212	161

2006 Reductions We have committed to drill four wells in Nigeria. The first two wells were unsuccessful. After drilling the second unsuccessful well in the first quarter of 2006, we determined that the capitalized costs related to these two wells should be impaired. Therefore, in the first quarter of 2006, we recognized an $85 million impairment of our investment in Nigeria equal to the costs to drill the two dry holes and a proportionate share of block-related costs. There was no tax benefit related to this impairment.

During the second quarter of 2006, we drilled two unsuccessful exploratory wells in Brazil and determined that the capitalized costs related to these two wells should be impaired. Therefore, in the second quarter of 2006, we recognized a $16 million impairment of our investment in Brazil equal to the costs to drill the two dry holes and a proportionate share of block-related costs. There was no tax benefit related to this impairment. The two wells were unrelated to Devon's Polvo development project in Brazil.

As a result of a decline in projected future net cash flows, the carrying value of our Russian properties exceeded the full cost ceiling by $10 million at the end of the third quarter of 2006. Therefore, we recognized a $20 million reduction of the carrying value of our oil and gas properties in Russia, offset by a $10 million deferred income tax benefit.

2005 Reductions Our interests in Angola were acquired through the 2003 Ocean Energy merger. Our Angolan drilling program discovered no proven reserves. After drilling three unsuccessful wells in the fourth quarter of 2005, we determined that all of the Angolan capitalized costs should be impaired.

Prior to the fourth quarter of 2005, we were capitalizing the costs of previous unsuccessful efforts in Brazil pending the determination of whether proved reserves would be recorded in Brazil. We have been successful in our drilling efforts on block BM-C-8 in Brazil and are currently developing the Polvo project on this block. The ultimate value of the Polvo project is expected to be in excess of the sum of its related costs, plus the costs of the previous unrelated unsuccessful efforts in Brazil which were capitalized. However, the Polvo proved reserves will be recorded over a period of time. At the end of 2005, it was expected that a small initial portion of the proved reserves ultimately expected at Polvo would be recorded in 2006. Based on preliminary estimates developed in the fourth quarter of 2005, the value of this initial partial booking of proved reserves was not sufficient to offset the sum of the related proportionate Polvo costs plus the costs of the previous unrelated unsuccessful efforts. Therefore, we determined that the prior unsuccessful costs unrelated to the Polvo project should be impaired. These costs totaled approximately $42 million. There was no tax benefit related to this Brazilian impairment.

Change in Fair Value of Derivative Financial Instruments

The details of the changes in fair value of derivative financial instruments between 2004 and 2006 are shown in the table below.

	2006	2005	2004
	(IN MILLIONS)		
Option embedded in exchangeable debentures	$ 181	54	58
Non-qualifying commodity hedges	—	39	—
Ineffectiveness of commodity hedges	—	5	5
Interest rate swaps	(3)	(4)	(1)
Total	$ 178	94	62

The change in the fair value of the embedded option relates to the debentures exchangeable into shares of Chevron Corporation common stock. These expenses were caused primarily by increases in the price of Chevron Corporation's common stock.

In 2005, we recognized a $39 million loss on certain oil derivative financial instruments that no longer qualified for hedge accounting because the hedged production exceeded actual and projected production under these contracts. The lower than expected production was caused primarily by hurricanes that affected offshore production in the Gulf of Mexico.

Other Income, Net

The following schedule includes the components of other income between 2004 and 2006.

		2006	2005	2004
			(IN MILLIONS)	
Interest and dividend income	$	100	95	45
Net gain on sales of non-oil and gas property and equipment		6	150	33
Loss on derivative financial instruments		—	(48)	—
Gains from changes in foreign exchange rates		—	2	23
Other		9	(1)	25
Total	$	115	198	126

Interest and dividend income increased from 2004 to 2005 primarily due to an increase in cash and short-term investment balances and higher interest rates.

During 2005, we sold certain non-core midstream assets for a net gain of $150 million. Also during 2005, we incurred a $55 million loss on certain commodity hedges that no longer qualified for hedge accounting and were settled prior to the end of their original term. These hedges related to U.S. and Canadian oil production from properties sold as part of our 2005 property divestiture program. This loss was partially offset by a $7 million gain related to interest rate swaps that were settled prior to the end of their original term in conjunction with the early redemption of the $400 million 6.75% senior notes in 2005.

The gains in 2005 and 2004 from changes in foreign exchange rates were primarily related to $400 million of Canadian subsidiary debt that was denominated in U.S. dollars. The debt was retired in 2005.

Income Taxes

The following table presents our total income tax expense related to continuing operations and a reconciliation of our effective income tax rate to the U.S. statutory income tax rate for each of the past three years. The primary factors causing our effective rates to vary from 2004 to 2006, and differ from the U.S. statutory rate, are discussed below.

		2006	2005	2004
			(IN MILLIONS)	
Total income tax expense	$	1,189	1,606	1,095
U.S. statutory income tax rate		35%	35%	35%
Canadian statutory rate reductions		(6%)	—	(1%)
Texas income-based tax		1%	—	—
United States manufacturing deduction		—	(1%)	—
Repatriation of Canadian earnings		—	1%	—
Other		—	1%	(1%)
Effective income tax rate		30%	36%	33%

In 2006, 2005 and 2004, deferred income taxes were reduced $243 million, $14 million and $36 million, respectively, due to Canadian statutory rate reductions that were enacted in each such year.

In 2006, deferred income taxes increased $39 million due to the effect of a new income-based tax enacted by the state of Texas that replaces a previous franchise tax. The new tax is effective January 1, 2007.

In 2006 and 2005, income taxes were reduced $12 million and $25 million, respectively, due to a new U.S. tax deduction for companies with domestic production activities, including oil and gas extraction.

In 2005, we recognized $28 million of taxes related to our repatriation of $545 million to the U.S. The cash was repatriated due to tax legislation that allowed qualifying companies to repatriate cash from foreign operations at a reduced income tax rate. Substantially all of the cash repatriated by us in 2005 related to earnings of our Canadian subsidiary.

Earnings From Discontinued Operations

On November 14, 2006, we announced our plans to divest our operations in Egypt. We anticipate completing the sale of our Egyptian operations in the first half of 2007. Pursuant to accounting rules for discontinued operations, Egypt is considered a discontinued operation at the end of 2006. As a result, the Egypt financial results for 2006 and all prior periods have been reclassified and are presented as discontinued operations.

Following are the components of the results of discontinued operations between 2004 and 2006.

		2006	2005	2004
			(IN MILLIONS)	
Earnings from discontinued operations before income taxes	$	22	46	17
Income tax (benefit) expense		(1)	15	12
Earnings from discontinued operations	$	23	31	5

CAPITAL RESOURCES, USES AND LIQUIDITY

The following discussion of capital resources and liquidity should be read in conjunction with the consolidated financial statements included in this report.

Sources and Uses of Cash

The following table presents the sources and uses of our cash and cash equivalents from 2004 to 2006. The table presents capital expenditures on a cash basis. Therefore, these amounts differ from the amounts of capital expenditures, including accruals, that are referred to elsewhere in this document. Additional discussion of these items follows the table.

		2006	2005	2004
			(IN MILLIONS)	
SOURCES OF CASH AND CASH EQUIVALENTS:				
Operating cash flow – continuing operations	$	5,936	5,514	4,789
Sales of property and equipment		40	2,151	95
Net commercial paper borrowings		1,808	—	—
Stock option exercises		73	124	268
Net decrease in short-term investments		106	287	—
Other		36	—	—
Total sources of cash and cash equivalents		7,999	8,076	5,152
USES OF CASH AND CASH EQUIVALENTS:				
Capital expenditures		(7,551)	(4,026)	(3,058)
Debt repayments		(862)	(1,258)	(973)
Repurchases of common stock		(253)	(2,263)	(189)
Dividends		(209)	(146)	(107)
Net increase in short-term investments		—	—	(626)
Total uses of cash and cash equivalents		(8,875)	(7,693)	(4,953)
Increase (decrease) from continuing operations		(876)	383	199
Increase (decrease) from discontinued operations		13	34	(18)
Effect of foreign exchange rates		13	37	39
Net increase (decrease) in cash and cash equivalents	$	(850)	454	220
Cash and cash equivalents at end of year	$	756	1,606	1,152
Short-term investments at end of year	$	574	680	967

Operating Cash Flow – Continuing Operations Net cash provided by operating activities ("operating cash flow") is our primary source of capital and liquidity. Changes in operating cash flow are largely due to the same factors that affect our net earnings, with the exception of those earnings changes due to such noncash expenses as DD&A, property impairments, derivative fair value changes and deferred income tax expense. As a result, our operating cash flow increased in 2006 and 2005 compared to the previous years largely due to increases in net earnings, as discussed in the "Results of Operations" section of this report.

Sales of Property and Equipment In 2005, we generated $2.2 billion in pre-tax proceeds from sales of property and equipment. These consisted of $2.0 billion related to the sale of non-core oil and gas properties and $0.2 billion related to the sale of non-core midstream assets. Net of related income taxes, these proceeds were $1.8 billion for oil and gas properties and $0.1 billion for midstream assets.

Net Commercial Paper Borrowings On June 29, 2006, we acquired Chief for $2 billion of cash and the assumption of $0.2 billion of liabilities. We funded a portion of the purchase price with $1.4 billion of borrowings issued under our commercial paper program. As a result of the Chief acquisition and success in other onshore U.S. locations, we accelerated certain oil and gas development activities into the last half of 2006. We borrowed an additional $0.4 billion of commercial paper to fund this accelerated development.

Capital Expenditures The increases in operating cash flow have enabled us to invest larger amounts in capital projects. As a result, excluding the acquisition of the Chief properties, our capital expenditures increased 38% in 2006. The majority of this increase related to our expenditures for the acquisition, drilling or development of oil and gas properties, which totaled $5.0 billion in 2006, excluding the Chief acquisition. Inflationary pressure driven by higher commodity prices and increased drilling activities in the Barnett Shale, Gulf of Mexico, Carthage and Groesbeck areas of the U.S. contributed to the increase. In addition, the payouts of our carried interests in Azerbaijan in the last half of 2006 and the weaker U.S. dollar impact on our Canadian operations also contributed to the increase.

Capital expenditures in 2005 increased 32% compared to 2004 primarily due to an increase in our expenditures for the acquisition, drilling or development of oil and gas properties, which totaled $3.9 billion in 2005. Increased drilling activities in the Barnett Shale, the approximately $200 million acquisition of Iron River acreage in Canada and the $74 million purchase of the Serpentina FPSO in offshore Equatorial Guinea were large contributors to the increase. Inflationary pressure driven by higher commodity prices and the weaker U.S. dollar also caused our expenditures to increase from 2004 to 2005.

Debt Repayments Our net debt retirements were $0.9 billion, $1.3 billion and $1.0 billion in 2006, 2005 and 2004, respectively. These amounts consisted of payments at the scheduled maturity dates with the exception of the following payments. The 2006 amount includes $0.2 billion related to the repayment of debt acquired in the Chief acquisition. The 2005 amount includes $0.8 billion related to the retirement of zero coupon convertible debentures due in 2020 and 6.75% notes due in 2011. The 2004 amount includes $635 million for the payment of the outstanding balance under a $3 billion term loan credit facility due in 2006.

Repurchases of Common Stock In August 2005, we completed a share repurchase program that began in October 2004. Under this program, we repurchased 49.6 million shares of our common stock at a total cost of $2.3 billion, or $46.69 per share. In August 2005, we announced another program to repurchase up to an additional 50 million shares of our common stock. During 2005 and 2006, we repurchased 6.5 million shares for $387 million, or $59.80 per share, under this program.

Dividends Our common stock dividends were $199 million, $136 million and $97 million in 2006, 2005 and 2004, respectively. We also paid $10 million of preferred stock dividends in 2006, 2005 and 2004. The 2006 and 2005 increases in common stock dividends were primarily related to a 50% increase in the dividend rate in the first quarter of both 2006 and 2005, partially offset by a decrease in outstanding shares due to share repurchases.

Changes in Short-Term Investments To maximize our income on available cash balances, we invest in highly liquid, short-term investments. The purchase and sale of these short-term investments will cause cash and cash equivalents to decrease and increase, respectively. Short-term investment balances decreased $106 million and $287 million in 2006 and 2005, respectively, and increased $626 million in 2004.

Liquidity

Historically, our primary source of capital and liquidity has been operating cash flow. Additionally, we maintain a revolving line of credit and a commercial paper program which can be accessed as needed to supplement operating cash flow. Other available sources of capital and liquidity include the issuance of equity securities and long-term debt. During 2007, another major source of liquidity will be proceeds from the sales of our operations in Egypt and West Africa. We expect the combination of these sources of capital will be more than adequate to fund future capital expenditures, debt repayments, common stock repurchases, and other contractual commitments as discussed later in this section.

Operating Cash Flow Our operating cash flow has increased nearly 25% since 2004, reaching a total of $5.9 billion in 2006. We expect operating cash flow to continue to be our primary source of liquidity. Our operating cash flow is sensitive to many variables, the most volatile of which is pricing of the oil, natural gas and NGLs produced. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict.

We periodically believe it appropriate to mitigate some of the risk inherent in oil and natural gas prices. We have used a variety of avenues to achieve this partial risk mitigation. We have utilized price collars to set minimum and maximum prices on a portion of our production. We have also utilized various price swap contracts and fixed-price physical delivery contracts to fix the price to be received for a portion of future oil and natural gas production. Based on contracts currently in place, approximately 5% of our estimated 2007 natural gas production (3% of our total Boe production) is subject to either price collars, swaps or fixed-price contracts.

Commodity prices can also affect our operating cash flow through an indirect effect on operating expenses. Significant commodity price increases, as experienced in recent years, can lead to an increase in drilling and development activities. As a result, the demand and cost for people, services, equipment and materials may also increase, causing a negative impact on our cash flow.

Credit Lines Another source of liquidity is our $2.5 billion five-year, syndicated, unsecured revolving line of credit (the "Senior Credit Facility"). The Senior Credit Facility includes a five-year revolving Canadian subfacility in a maximum amount of U.S. $500 million. Amounts borrowed under the Senior Credit Facility may, at our election, bear interest at various fixed rate options for periods of up to twelve months. Such rates are generally less than the prime rate. However, we may elect to borrow at the prime rate. As of December 31, 2006, there were no borrowings under the Senior Credit Facility. The available capacity under the Senior Credit Facility as of December 31, 2006, net of $1.8 billion of outstanding commercial paper and $284 million of outstanding letters of credit, was approximately $408 million.

The Senior Credit Facility matures on April 7, 2011, and all amounts outstanding will be due and payable at that time unless the maturity is extended. Prior to each April 7 anniversary date, we have the option to extend the maturity of the Senior Credit Facility for one year, subject to the approval of the lenders. We are working to obtain lender approval to extend the current maturity date of April 7, 2011 to April 7, 2012. If successful, this maturity date extension will be effective April 7, 2007, provided we have not experienced a "material adverse effect," as defined in the Senior Credit Facility agreement, at that date.

The Senior Credit Facility contains only one material financial covenant. This covenant requires our ratio of total funded debt to total capitalization to be less than 65%. The credit agreement contains definitions of total funded debt and total capitalization that include adjustments to the respective amounts reported in our consolidated financial statements. As defined in the agreement, total funded debt excludes the debentures that are exchangeable into shares of Chevron Corporation common stock. Also, total capitalization is adjusted to add back noncash financial writedowns such as full cost ceiling impairments or goodwill impairments. As of December 31, 2006, our debt to capitalization ratio as calculated pursuant to this covenant was 27.3%.

Our access to funds from the Senior Credit Facility is not restricted under any "material adverse effect" clauses. It is not uncommon for credit agreements to include such clauses. These clauses can remove the obligation of the banks to fund the credit line if any condition or event would reasonably be expected to have a material and adverse effect on the borrower's financial condition, operations, properties or business considered as a whole, the borrower's ability to make timely debt payments, or the enforceability of material terms of the credit agreement. While our Senior Credit Facility includes covenants that require us to report a condition or event having a material adverse effect, the obligation of the banks to fund the Senior Credit Facility is not conditioned on the absence of a material adverse effect.

We also have access to short-term credit under our commercial paper program. Total borrowings under the commercial paper program may not exceed $2 billion. Also, any borrowings under the commercial paper program reduce available capacity under the Senior Credit Facility on a dollar-for-dollar basis. Commercial paper debt generally has a maturity of between seven and 90 days, although it can have a maturity of up to 365 days, and bears interest at rates agreed to at the time of the borrowing. The interest rate is based on a standard index such as the Federal Funds Rate, LIBOR, or the money market rate as found on the commercial paper market. As of December 31, 2006, we had $1.8 billion of commercial paper debt outstanding at an average rate of 5.37%.

Debt Ratings We receive debt ratings from the major ratings agencies in the United States. In determining our debt ratings, the agencies consider a number of items including, but not limited to, debt levels, planned asset sales, near-term and long-term production growth opportunities and capital allocation challenges. Liquidity, asset quality, cost structure, reserve mix, and commodity pricing levels are also considered by the rating agencies. Our current debt ratings are BBB with a positive outlook by Standard & Poor's, Baa2 with a positive outlook by Moody's and BBB with a positive outlook by Fitch.

There are no "rating triggers" in any of our contractual obligations that would accelerate scheduled maturities should our debt rating fall below a specified level. Our cost of borrowing under our Senior Credit Facility is predicated on our corporate debt rating. Therefore, even though a ratings downgrade would not accelerate scheduled maturities, it would adversely impact the interest rate on any borrowings under our Senior Credit Facility. Under the terms of the Senior Credit Facility, a one-notch downgrade would increase the fully-drawn borrowing costs for the Senior Credit Facility from LIBOR plus 45 basis points to a new rate of LIBOR plus 65 basis points. A ratings downgrade could also adversely impact our ability to economically access debt markets in the future. As of December 31, 2006, we were not aware of any potential ratings downgrades being contemplated by the rating agencies.

Capital Expenditures In February 2007, we provided guidance for our 2007 capital expenditures which are expected to range from $5.7 billion to $6.2 billion. This represents the largest planned use of our 2007 operating cash flow, with the high end of the range being 11% higher than our 2006 capital expenditures, excluding the Chief acquisition. To a certain degree, the ultimate timing of these capital expenditures is within our control. Therefore, if oil and natural gas prices fluctuate from current estimates, we could choose to defer a portion of these planned 2007 capital expenditures until later periods, or accelerate capital expenditures planned for periods beyond 2007 to achieve the desired balance between sources and uses of liquidity. Based upon current oil and natural gas price expectations for 2007, we anticipate having adequate capital resources to fund our 2007 capital expenditures.

Common Stock Repurchase Program In August 2005, we announced a program to repurchase up to 50 million shares of our common stock. We had repurchased 6.5 million shares under this program through the middle of 2006 when the program was suspended as a result of the Chief acquisition. In conjunction with the sales of our Egyptian and West African operations, we expect to resume this repurchase program in late 2007 by using a portion of the sales proceeds to repurchase common stock. Although this program expires at the end of 2007, it could be extended if necessary.

Contractual Obligations A summary of our contractual obligations as of December 31, 2006, is provided in the following table.

		TOTAL	LESS THAN 1 YEAR	1-3 YEARS	3-5 YEARS	MORE THAN 5 YEARS
			PAYMENTS DUE BY PERIOD			
				(IN MILLIONS)		
Long-term debt (1)	$	7,770	2,208	937	2,100	2,525
Interest expense (2)		5,797	492	764	690	3,851
Drilling and facility obligations (3)		2,993	886	1,137	844	126
Asset retirement obligations (4)		894	61	75	143	615
Firm transportation agreements (5)		574	123	173	106	172
Lease obligations (6)		595	80	163	123	229
Other		37	28	5	4	—
Total	$	18,660	3,878	3,254	4,010	7,518

(1) Long-term debt amounts represent scheduled maturities of our debt obligations at December 31, 2006, excluding $5 million of fair value adjustments and $8 million of net premiums included in the carrying value of debt. The "Less than 1 Year" amount includes $1.8 billion of short-term commercial paper borrowings. We intend to use the proceeds from the sales of our Egyptian and West African assets to repay our outstanding commercial paper. The "1-3 Years" amount includes $760 million related to our debentures exchangeable into shares of Chevron Corporation common stock. As of December 31, 2006, we beneficially owned approximately 14.2 million shares of Chevron common stock for possible exchange for the exchangeable debentures. In addition, $284 million of letters of credit that have been issued by commercial banks on our behalf are excluded from the table. The majority of these letters of credit, if funded, would become borrowings under our revolving credit facility. Most of these letters of credit have been granted by financial institutions to support our international and Canadian drilling commitments.

(2) Interest expense amounts represent the scheduled fixed-rate and variable-rate cash payments related to our debt. Interest on our variable-rate debt was estimated based upon expected future interest rates as of December 31, 2006.

(3) Drilling and facility obligations represent contractual agreements with third party service providers to procure drilling rigs and other related services for developmental and exploratory drilling and facilities construction. Included in the $3.0 billion total is $1.9 billion which relates to long-term contracts for three deepwater drilling rigs and certain other contracts for onshore drilling and facility obligations in which drilling or facilities construction has not commenced. The $1.9 billion represents the gross commitment under these contracts. Our ultimate payment for these commitments will be reduced by the amounts billed to our working interest partners. Payments for these commitments, net of amounts billed to partners, will be capitalized as a component of oil and gas properties.

(4) Asset retirement obligations represent estimated discounted costs for future dismantlement, abandonment and rehabilitation costs. These obligations are recorded as liabilities on our December 31, 2006 balance sheet.

(5) Firm transportation agreements represent "ship or pay" arrangements whereby we have committed to ship certain volumes of oil, gas and NGLs for a fixed transportation fee. We have entered into these agreements to aid the movement of our gas production to market. We expect to have sufficient production to utilize the majority of these transportation services.

(6) Lease obligations consist of operating leases for office space and equipment, an offshore platform spar and FPSO's. Office and equipment leases represent non-cancelable leases for office space and equipment used in our daily operations. We have an offshore platform spar that is being used in the development of the Nansen field in the Gulf of Mexico. This spar is subject to a 20-year lease and contains various options whereby we may purchase the lessors' interests in the spar. We have guaranteed that the spar will have a residual value at the end of the term equal to at least 10% of the fair value of the spar at the inception of the lease. The total guaranteed value is $14 million in 2022. However, such amount may be reduced under the terms of the lease agreement. In 2005, we sold our interests in the Boomvang field in the Gulf of Mexico, which has a spar lease with terms similar to those of the Nansen lease. As a result of the sale, we are subleasing the Boomvang Spar. The table above does not include any amounts related to the Boomvang spar lease. However, if the sublessee were to default on its obligation, we would continue to be obligated to pay the periodic lease payments and any guaranteed value required at the end of the term. We also lease two FPSO's that are being used in the Panyu project offshore China and the Polvo project offshore Brazil. The Panyu FPSO lease term expires in September 2009. The Polvo FPSO lease term expires in 2014.

Pension Funding and Estimates *Funded Status* As compared to the "projected benefit obligation," our qualified and nonqualified defined benefit plans were underfunded by $178 million and $133 million at December 31, 2006 and 2005, respectively. A detailed reconciliation of the 2006 changes to our underfunded status is included in Note 6 to the accompanying consolidated financial statements. Of the $178 million underfunded status at the end of 2006, $156 million is attributable to various nonqualified defined benefit plans which have no plan assets. However, we have established certain trusts to fund the benefit obligations of such nonqualified plans. As of December 31, 2006, these trusts had investments with a fair value of $59 million. The value of these trusts is included in noncurrent other assets in our accompanying consolidated balance sheets.

As compared to the "accumulated benefit obligation," our qualified defined benefit plans were overfunded by $59 million at December 31, 2006. The accumulated benefit obligation differs from the projected benefit obligation in that the former includes no assumption about future compensation levels. Our current intentions are to provide sufficient funding in future years to ensure the accumulated benefit obligation remains fully funded. The actual amount of contributions required during this period will depend on investment returns from the plan assets. Required contributions also depend upon changes in actuarial assumptions made during the same period, particularly the discount rate used to calculate the present value of the accumulated benefit obligation. For 2007, we anticipate the accumulated benefit obligation will remain fully funded without contributing to our defined benefit plans. Therefore, we don't expect to contribute to the plans during 2007.

Pension Estimate Assumptions Our pension expense is recognized on an accrual basis over employees' approximate service periods and is generally calculated independent of funding decisions or requirements. We recognized expense for our defined benefit pension plans of $31 million, $26 million and $26 million in 2006, 2005 and 2004, respectively. We estimate that our pension expense will approximate $43 million in 2007.

The calculation of pension expense and pension liability requires the use of a number of assumptions. Changes in these assumptions can result in different expense and liability amounts, and future actual experience can differ from the assumptions. We believe that the two most critical assumptions affecting pension expense and liabilities are the expected long-term rate of return on plan assets and the assumed discount rate.

We assumed that our plan assets would generate a long-term weighted average rate of return of 8.40% at both December 31, 2006 and 2005. We developed these expected long-term rate of return assumptions by evaluating input from external consultants and economists as well as long-term inflation assumptions. The expected long-term rate of return on plan assets is based on a target allocation of investment types in such assets. The target investment allocation for our plan assets is 50% U.S. large cap equity securities; 15% U.S. small cap equity securities, equally allocated between growth and value; 15% international equity securities, equally allocated between growth and value; and 20% debt securities. We expect our long-term asset allocation on average to approximate the targeted allocation. We regularly review our actual asset allocation and periodically rebalance the investments to the targeted allocation when considered appropriate.

Pension expense increases as the expected rate of return on plan assets decreases. A decrease in our long-term rate of return assumption of 100 basis points (from 8.40% to 7.40%) would increase the expected 2007 pension expense by $6 million.

We discounted our future pension obligations using a weighted average rate of 5.72% at both December 31, 2006 and 2005. The discount rate is determined at the end of each year based on the rate at which obligations could be effectively settled. This rate is based on high-quality bond yields, after allowing for call and default risk. We consider high quality corporate bond yield indices, such as Moody's Aa, when selecting the discount rate.

The pension liability and future pension expense both increase as the discount rate is reduced. Lowering the discount rate by 25 basis points (from 5.72% to 5.47%) would increase our pension liability at December 31, 2006, by $25 million, and increase estimated 2007 pension expense by $3 million.

At December 31, 2006, we had actuarial losses of $214 million which will be recognized as a component of pension expense in future years. These losses are primarily due to reductions in the discount rate since 2001 and increases in participant wages. We estimate that approximately $15 million and $13 million of the unrecognized actuarial losses will be included in pension expense in 2007 and 2008, respectively. The $15 million estimated to be recognized in 2007 is a component of the total estimated 2007 pension expense of $43 million referred to earlier in this section.

Future changes in plan asset returns, assumed discount rates and various other factors related to the participants in our defined benefit pension plans will impact future pension expense and liabilities. We cannot predict with certainty what these factors will be in the future.

On August 17, 2006, the Pension Protection Act was signed into law. Beginning in 2008, this act will cause extensive changes in the determination of both the minimum required contribution and the maximum tax deductible limit. Because the new required contribution will approximate our current policy of fully funding the accumulated benefit obligation, the changes are not expected to have a significant impact on future cash flows.

Beginning with our December 31, 2006 balance sheet, Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106, and 132(R)* requires us to recognize on our consolidated balance sheet the funded status of our defined benefit plans. The funded status is measured as the difference between the projected benefit obligation and the fair value of plan assets. As a result, we recognized as liabilities the actuarial losses and other costs that were previously unrecognized under prior accounting rules, and the net effect was also recorded as a reduction to stockholders' equity on December 31, 2006. This reduction was $140 million, or less than 1% of our stockholders' equity.

CONTINGENCIES AND LEGAL MATTERS

For a detailed discussion of contingencies and legal matters, see Note 8 of the accompanying consolidated financial statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

The critical accounting policies used by management in the preparation of our consolidated financial statements are those that are important both to the presentation of our financial condition and results of operations and require significant judgments by management with regard to estimates used. Our critical accounting policies and significant judgments and estimates related to those policies are described below. We have reviewed these critical accounting policies with the Audit Committee of the Board of Directors.

Full Cost Ceiling Calculations

Policy Description We follow the full cost method of accounting for our oil and gas properties. The full cost method subjects companies to quarterly calculations of a "ceiling," or limitation on the amount of properties that can be capitalized on the balance sheet. The ceiling limitation is the discounted estimated after-tax future net revenues from proved oil and gas properties, excluding future cash outflows associated with settling asset retirement obligations included in the net book value of oil and gas properties, plus the cost of properties not subject to amortization. If our net book value of oil and gas properties, less related deferred income taxes, is in excess of the calculated ceiling, the excess must be written off as an expense, except as discussed in the following paragraph. The ceiling limitation is imposed separately for each country in which we have oil and gas properties.

If, subsequent to the end of the quarter but prior to the applicable financial statements being published, prices increase to levels such that the ceiling would exceed the costs to be recovered, a writedown otherwise indicated at the end of the quarter is not required to be recorded. A writedown indicated at the end of a quarter is also not required if the value of additional reserves proved up on properties after the end of the quarter but prior to the publishing of the financial statements would result in the ceiling exceeding the costs to be recovered, as long as the properties were owned at the end of the quarter. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period.

Judgments and Assumptions The discounted present value of future net revenues for our proved oil, natural gas and NGL reserves is a major component of the ceiling calculation, and represents the component that requires the most subjective judgments. Estimates of reserves are forecasts based on engineering data, projected future rates of production and the timing of future expenditures. The process of estimating oil, natural gas and NGL reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. Different reserve engineers may make different estimates of reserve quantities based on the same data. Certain of our reserve estimates are prepared or audited by outside petroleum consultants, while other reserve estimates are prepared by our engineers. See Note 15 of the accompanying consolidated financial statements.

The passage of time provides more qualitative information regarding estimates of reserves, and revisions are made to prior estimates to reflect updated information. In the past five years, annual revisions to our reserve estimates, which have been both increases and decreases in individual years, have averaged approximately 1% of the previous year's estimate. However, there can be no assurance that more significant revisions will not be necessary in the future. If future significant revisions are necessary that reduce previously estimated reserve quantities, it could result in a full cost property writedown. In addition to the impact of the estimates of proved reserves on the calculation of the ceiling, estimates of proved reserves are also a significant component of the calculation of DD&A.

While the quantities of proved reserves require substantial judgment, the associated prices of oil, natural gas and NGL reserves, and the applicable discount rate, that are used to calculate the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that a 10% discount factor be used and that prices and costs in effect as of the last day of the period are held constant indefinitely. Therefore, the future net revenues associated with the estimated proved reserves are not based on our assessment of future prices or costs. Rather, they are based on such prices and costs in effect as of the end of each quarter when the ceiling calculation is performed. In calculating the ceiling, we adjust the end-of-period price by the effect of cash flow hedges in place. This adjustment requires little judgment as the end-of-period price is adjusted using the contract prices for our cash flow hedges. We had no such hedges outstanding at December 31, 2006.

Because the ceiling calculation dictates that prices in effect as of the last day of the applicable quarter are held constant indefinitely, and requires a 10% discount factor, the resulting value is not indicative of the true fair value of the reserves. Oil and natural gas prices have historically been volatile. On any particular day at the end of a quarter, prices can be either substantially higher or lower than our long-term price forecast that is a barometer for true fair value. Therefore, oil and gas property writedowns that result from applying the full cost ceiling limitation, and that are caused by fluctuations in price as opposed to reductions to the underlying quantities of reserves, should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves.

Derivative Financial Instruments

Policy Description The majority of our historical derivative instruments have consisted of commodity financial instruments used to manage our cash flow exposure to oil and gas price volatility. We have also entered into interest rate swaps to manage our exposure to interest rate volatility. The interest rate swaps mitigate either the cash flow effects of interest rate fluctuations on interest expense for variable-rate debt instruments, or the fair value effects of interest rate fluctuations on fixed-rate debt. We also have an embedded option derivative related to the fair value of our debentures exchangeable into shares of Chevron Corporation common stock.

All derivatives are recognized at their current fair value on our balance sheet. Changes in the fair value of derivative financial instruments are recorded in the statement of operations unless specific hedge accounting criteria are met. If such criteria are met for cash flow hedges, the effective portion of the change in the fair value is recorded directly to accumulated other comprehensive income, a component of stockholders' equity, until the hedged transaction occurs. The ineffective portion of the change in fair value is recorded in the statement of operations. If hedge accounting criteria are met for fair value hedges, the change in the fair value is recorded in the statement of operations with an offsetting amount recorded for the change in fair value of the hedged item.

A derivative instrument qualifies for hedge accounting treatment if we designate the instrument as such on the date the derivative contract is entered into or the date of an acquisition or business combination which includes derivative contracts. Additionally, we must document the relationship between the hedging instrument and hedged item, as well as the risk-management objective and strategy for undertaking the instrument. We must also assess, both at the instrument's inception and on an ongoing basis, whether the derivative is highly effective in offsetting the change in cash flow of the hedged item.

Judgments and Assumptions The estimates of the fair values of our commodity derivative instruments require substantial judgment. For these instruments, we obtain forward price and volatility data for all major oil and gas trading points in North America from independent third parties. These forward prices are compared to the price parameters contained in the hedge agreements. The resulting estimated future cash inflows or outflows over the lives of the hedge contracts are discounted using LIBOR and money market futures rates for the first year and money market futures and swap rates thereafter. In addition, we estimate the option value of price floors and price caps using an option pricing model. These pricing and discounting variables are sensitive to the period of the contract and market volatility as well as changes in forward prices, regional price differentials and interest rates. Fair values of our other derivative instruments require less judgment to estimate and are primarily based on quotes from independent third parties such as counterparties or brokers.

Quarterly changes in estimates of fair value have only a minimal impact on our liquidity, capital resources or results of operations, as long as the derivative instruments qualify for hedge accounting treatment. Changes in the fair values of derivatives that do not qualify for hedge accounting treatment can have a significant impact on our results of operations, but generally will not impact our liquidity or capital resources. Settlements of derivative instruments, regardless of whether they qualify for hedge accounting, do have an impact on our liquidity and results of operations. Generally, if actual market prices are higher than the price of the derivative instruments, our net earnings and cash flow from operations will be lower relative to the results that would have occurred absent these instruments. The opposite is also true. Additional information regarding the effects that changes in market prices will have on our derivative financial instruments, net earnings and cash flow from operations is included in the "Quantitative and Qualitative Disclosures about Market Risk" section of this report.

Business Combinations

Policy Description We have grown substantially during recent years through acquisitions of other oil and natural gas companies. Most of these acquisitions have been accounted for using the purchase method of accounting, and recent accounting pronouncements require that all future acquisitions will be accounted for using the purchase method.

Under the purchase method, the acquiring company adds to its balance sheet the estimated fair values of the acquired company's assets and liabilities. Any excess of the purchase price over the fair values of the tangible and intangible net assets acquired is recorded as goodwill. Goodwill is assessed for impairment at least annually.

Judgments and Assumptions There are various assumptions we make in determining the fair values of an acquired company's assets and liabilities. The most significant assumptions, and the ones requiring the most judgment, involve the estimated fair values of the oil and gas properties acquired. To determine the fair values of these properties, we prepare estimates of oil, natural gas and NGL reserves. These estimates are based on work performed by our engineers and that of outside consultants. The judgments associated with these estimated reserves are described earlier in this section in connection with the full cost ceiling calculation.

However, there are factors involved in estimating the fair values of acquired oil, natural gas and NGL properties that require more judgment than that involved in the full cost ceiling calculation. As stated above, the full cost ceiling calculation applies end-of-period price and cost information to the reserves to arrive at the ceiling amount. By contrast, the fair value of reserves acquired in a business combination must be based on our estimates of future oil, natural gas and NGL prices. Our estimates of future prices are based on our own analysis of pricing trends. These estimates are based on current data obtained with regard to regional and worldwide supply and demand dynamics such as economic growth forecasts. They are also based on industry data regarding natural gas storage availability, drilling rig activity, changes in delivery capacity, trends in regional pricing differentials and other fundamental analysis. Forecasts of future prices from independent third parties are noted when we make our pricing estimates.

We estimate future prices to apply to the estimated reserve quantities acquired, and estimate future operating and development costs, to arrive at estimates of future net revenues. For estimated proved reserves, the future net revenues are then discounted using a rate determined appropriate at the time of the business combination based upon our cost of capital.

We also apply these same general principles to estimate the fair value of unproved properties acquired in a business combination. These unproved properties generally represent the value of probable and possible reserves. Because of their very nature, probable and possible reserve estimates are more imprecise than those of proved reserves. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net revenues of probable and possible reserves are reduced by what we consider to be an appropriate risk-weighting factor in each particular instance. It is common for the discounted future net revenues of probable and possible reserves to be reduced by factors ranging from 30% to 80% to arrive at what we consider to be the appropriate fair values.

Generally, in our business combinations, the determination of the fair values of oil and gas properties requires much more judgment than the fair values of other assets and liabilities. The acquired companies commonly have long-term debt that we assume in the acquisition, and this debt must be recorded at the estimated fair value as if we had issued such debt. However, significant judgment on our behalf is usually not required in these situations due to the existence of comparable market values of debt issued by peer companies.

Except for the 2002 Mitchell merger, our mergers and acquisitions have involved other entities whose operations were predominantly in the area of exploration, development and production activities related to oil and gas properties. However, in addition to exploration, development and production activities, Mitchell's business also included substantial marketing and midstream activities. Therefore, a portion of the Mitchell purchase price was allocated to the fair value of Mitchell's marketing and midstream facilities and equipment. This consisted primarily of natural gas processing plants and natural gas pipeline systems.

The Mitchell midstream assets primarily served gas producing properties that we also acquired from Mitchell. Therefore, certain of the assumptions regarding future operations of the gas producing properties were also integral to the value of the midstream assets. For example, future quantities of natural gas estimated to be processed by natural gas processing plants were based on the same estimates used to value the proved and unproved gas producing properties. Future expected prices for marketing and midstream product sales were also based on price cases consistent with those used to value the oil and gas producing assets acquired from Mitchell. Based on historical costs and known trends and commitments, we also estimated future operating and capital costs of the marketing and midstream assets to arrive at estimated future cash flows. These cash flows were discounted at rates consistent with those used to discount future net cash flows from oil and gas producing assets to arrive at our estimated fair value of the marketing and midstream facilities and equipment.

In addition to the valuation methods described above, we perform other quantitative analyses to support the indicated value in any business combination. These analyses include information related to comparable companies, comparable transactions and premiums paid.

In a comparable companies analysis, we review the public stock market trading multiples for selected publicly traded independent exploration and production companies with comparable financial and operating characteristics. Such characteristics are market capitalization, location of proved reserves and the characterization of those reserves that we deem to be similar to those of the party to the proposed business combination. We compare these comparable company multiples to the proposed business combination company multiples for reasonableness.

In a comparable transactions analysis, we review certain acquisition multiples for selected independent exploration and production company transactions and oil and gas asset packages announced recently. We compare these comparable transaction multiples to the proposed business combination transaction multiples for reasonableness.

In a premiums paid analysis, we use a sample of selected independent exploration and production company transactions in addition to selected transactions of all publicly traded companies announced recently, to review the premiums paid to the price of the target one day, one week and one month prior to the announcement of the transaction. We use this information to determine the mean and median premiums paid and compare them to the proposed business combination premium for reasonableness.

While these estimates of fair value for the various assets acquired and liabilities assumed have no effect on our liquidity or capital resources, they can have an effect on the future results of operations. Generally, the higher the fair value assigned to both the oil and gas properties and non-oil and gas properties, the lower future net earnings will be as a result of higher future depreciation, depletion and amortization expense. Also, a higher fair value assigned to the oil and gas properties, based on higher future estimates of oil and gas prices, will increase the likelihood of a full cost ceiling writedown in the event that subsequent oil and gas prices drop below our price forecast that was used to originally determine fair value. A full cost ceiling writedown would have no effect on our liquidity or capital resources in that period because it is a noncash charge, but it would adversely affect results of operations. As discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Resources, Uses and Liquidity," in calculating our debt-to-capitalization ratio under our credit agreement, total capitalization is adjusted to add back noncash financial writedowns such as full cost ceiling property impairments or goodwill impairments.

Our estimates of reserve quantities are one of the many estimates that are involved in determining the appropriate fair value of the oil and gas properties acquired in a business combination. As previously disclosed in our discussion of the full cost ceiling calculations, during the past five years, our annual revisions to our reserve estimates have averaged approximately 1%. As discussed in the preceding paragraphs, there are numerous estimates in addition to reserve quantity estimates that are involved in determining the fair value of oil and gas properties acquired in a business combination. The inter-relationship of these estimates makes it impractical to provide additional quantitative analyses of the effects of changes in these estimates.

Valuation of Goodwill

Policy Description Goodwill is tested for impairment at least annually. This requires us to estimate the fair values of our own assets and liabilities in a manner similar to the process described above for a business combination. Therefore, considerable judgment similar to that described above in connection with estimating the fair value of an acquired company in a business combination is also required to assess goodwill for impairment.

Judgments and Assumptions Generally, the higher the fair value assigned to both the oil and gas properties and non-oil and gas properties, the lower goodwill would be. A lower goodwill value decreases the likelihood of an impairment charge. However, unfavorable changes in reserves or in our price forecast would increase the likelihood of a goodwill impairment charge. A goodwill impairment charge would have no effect on liquidity or capital resources. However, it would adversely affect our results of operations in that period.

Due to the inter-relationship of the various estimates involved in assessing goodwill for impairment, it is impractical to provide quantitative analyses of the effects of potential changes in these estimates, other than to note the historical average changes in our reserve estimates previously set forth.

RECENTLY ISSUED ACCOUNTING STANDARDS NOT YET ADOPTED

In June 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109*. Interpretation No. 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes*. This Interpretation is effective for fiscal years beginning after December 15, 2006, and we will adopt it in the first quarter of 2007. We do not expect the adoption of Interpretation No. 48 to have a material impact on our financial statements and related disclosures.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, *Fair Value Measurements*. Statement No. 157 provides a common definition of fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. However, this Statement does not require any new fair value measurements. Statement No. 157 is effective for fiscal years beginning after November 15, 2007. We are currently assessing the effect, if any, the adoption of Statement No. 157 will have on our financial statements and related disclosures.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106, and 132(R)*. Statement No. 158 requires the recognition of the overfunded or underfunded status of a defined benefit postretirement plan in the balance sheet. We adopted this recognition requirement as of December 31, 2006. The effects of this adoption are summarized in Note 6 of the accompanying consolidated financial statements. Statement No. 158 also requires the measurement of plan assets and benefit obligations as of the date of the employer's fiscal year-end. The Statement provides two alternatives to transition to a fiscal year-end measurement date. This measurement requirement is effective for fiscal years ending after December 15, 2008. We have not yet adopted this measurement requirement, but we do not expect such adoption to have a material effect on our results of operations, financial condition, liquidity or compliance with debt covenants.

In February 2007, the FASB issued Statement of Financial Accounting Standards No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115*. Statement No. 159 permits entities to choose to measure certain financial instruments and other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Unrealized gains and losses on any items for which we elect the fair value measurement option would be reported in earnings. Statement No. 159 is effective for fiscal years beginning after November 15, 2007. However, early adoption is permitted for fiscal years beginning on or before November 15, 2007, provided we also elect to apply the provisions of Statement No. 157, *Fair Value Measurements*, at the same time. We are currently assessing the effect, if any, the adoption of Statement No. 159 will have on our financial statements and related disclosures.

2007 ESTIMATES

The forward-looking statements provided in this discussion are based on our examination of historical operating trends, the information which was used to prepare the December 31, 2006 reserve reports and other data in our possession or available from third parties. These forward-looking statements were prepared assuming demand, curtailment, producibility and general market conditions for our oil, natural gas and NGLs during 2007 will be substantially similar to those of 2006, unless otherwise noted. Please refer to "Risk Factors to Forward-Looking Estimates" on page 101 for a discussion of relevant risk factors. Amounts related to Canadian operations have been converted to U.S. dollars using a projected average 2007 exchange rate of $0.89 U.S. dollar to $1.00 Canadian dollar.

On November 14, 2006, we announced our intent to divest our Egyptian oil and gas assets and terminate our operations in Egypt. We expect to complete this asset sale during the first half of 2007. Subsequently on January 23, 2007, we announced our intent to divest our West African oil and gas assets and terminate our operations in West Africa. We expect to complete this asset sale by the end of the third quarter in 2007. All Egyptian and West African related revenues, expenses and capital will be reported as discontinued operations in our 2007 financial statements. Accordingly, all forward-looking estimates in the following discussion exclude amounts related to our operations in Egypt and West Africa, unless otherwise noted. The assets held for sale represented less than five percent of our 2006 production and December 31, 2006 proved reserves.

Oil, Gas and NGL Production

Set forth in the following paragraphs are individual estimates of oil, gas and NGL production for 2007. We estimate, on a combined basis, that our 2007 oil, gas, and NGL production will total approximately 219 to 221 MMBoe. Of this total, approximately 92% is estimated to be produced from reserves classified as "proved" at December 31, 2006. The following estimates for oil, gas and NGL production are calculated at the midpoint of the estimated range for total production.

Oil Production Oil production in 2007 is expected to total approximately 55 MMBbls. Of this total, approximately 99% is estimated to be produced from reserves classified as "proved" at December 31, 2006. The expected production by area is as follows:

	MMBBLS
U.S. Onshore	10
U.S. Offshore	9
Canada	15
International	21

Oil Prices We have not fixed the price we will receive on any of our 2007 oil production. Our 2007 average prices for each of our areas are expected to differ from the NYMEX price as set forth in the following table. The NYMEX price is the monthly average of settled prices on each trading day for benchmark West Texas Intermediate crude oil delivered at Cushing, Oklahoma.

	EXPECTED RANGE OF OIL PRICES AS A % OF NYMEX PRICE
U.S. Onshore	86% to 96%
U.S. Offshore	90% to 100%
Canada	60% to 70%
International	83% to 93%

Gas Production Gas production in 2007 is expected to total approximately 841 Bcf. Of this total, approximately 88% is estimated to be produced from reserves classified as "proved" at December 31, 2006. The expected production by area is as follows:

	BCF
U.S. Onshore	557
U.S. Offshore	75
Canada	207
International	2

Gas Prices Our 2007 average prices for each of our areas are expected to differ from the NYMEX price as set forth in the following table. The NYMEX price is determined to be the first-of-month South Louisiana Henry Hub price index as published monthly in *Inside FERC*.

Based on contracts currently in place, we will have approximately 116 MMcf per day of gas production in 2007 that is subject to either fixed-price contracts, swaps, floors or collars. These amounts represent approximately 5% of our estimated gas production for 2007. Therefore, these various pricing arrangements are not expected to have a material impact on the ranges of estimated gas price realizations set forth in the following table.

	EXPECTED RANGE OF GAS PRICES AS A % OF NYMEX PRICE
U.S. Onshore	80% to 90%
U.S. Offshore	96% to 106%
Canada	80% to 90%
International	100% to 110%

NGL Production We expect our 2007 production of NGLs to total approximately 25 MMBbls. Of this total, approximately 95% is estimated to be produced from reserves classified as "proved" at December 31, 2006. The expected production by area is as follows:

	MMBBLS
U.S. Onshore	20
U.S. Offshore	1
Canada	4

Marketing and Midstream Revenues and Expenses

Marketing and midstream revenues and expenses are derived primarily from our natural gas processing plants and natural gas transport pipelines. These revenues and expenses vary in response to several factors. The factors include, but are not limited to, changes in production from wells connected to the pipelines and related processing plants, changes in the absolute and relative prices of natural gas and NGLs, provisions of the contract agreements and the amount of repair and workover activity required to maintain anticipated processing levels.

These factors, coupled with uncertainty of future natural gas and NGL prices, increase the uncertainty inherent in estimating future marketing and midstream revenues and expenses. Given these uncertainties, we estimate that marketing and midstream revenues will be between $1.70 billion and $2.10 billion, and marketing and midstream expenses will be between $1.31 billion and $1.67 billion.

Production and Operating Expenses

Our production and operating expenses include lease operating expenses, transportation costs and production taxes. These expenses vary in response to several factors. Among the most significant of these factors are additions to or deletions from the property base, changes in the general price level of services and materials that are used in the operation of the properties, the amount of repair and workover activity required and changes in production tax rates. Oil, natural gas and NGL prices also have an effect on lease operating expenses and impact the economic feasibility of planned workover projects. Given these uncertainties, we estimate that 2007 lease operating expenses (including transportation costs) will be between $1.70 billion and $1.77 billion. Additionally, we estimate our production taxes for 2007 to be between 3.6% and 4.1% of consolidated oil, natural gas and NGL revenues.

Depreciation, Depletion and Amortization ("DD&A")

The 2007 oil and gas property DD&A rate will depend on various factors. Most notable among such factors are the amount of proved reserves that will be added from drilling or acquisition efforts in 2007 compared to the costs incurred for such efforts, and the revisions to our year-end 2006 reserve estimates that, based on prior experience, are likely to be made during 2007.

Given these uncertainties, we expect our oil and gas property related DD&A rate will be between $11.00 per Boe and $11.50 per Boe. Based on these DD&A rates and the production estimates set forth earlier, oil and gas property related DD&A expense for 2007 is expected to be between $2.42 billion and $2.53 billion.

Additionally, we expect our depreciation and amortization expense related to non-oil and gas property fixed assets to total between $210 million and $220 million.

Accretion of Asset Retirement Obligation

Accretion of asset retirement obligation in 2007 is expected to be between $45 million and $55 million.

General and Administrative Expenses ("G&A")

Our G&A includes employee compensation and benefits costs and the costs of many different goods and services used in support of our business. G&A varies with the level of our operating activities and the related staffing and professional services requirements. In addition, employee compensation and benefits costs vary due to various market factors that affect the level and type of compensation and benefits offered to employees. Also, goods and services are subject to general price level increases or decreases. Therefore, significant variances in any of these factors from current expectations could cause actual G&A to vary materially from the estimate.

Given these limitations, G&A in 2007 is expected to be between $460 million and $480 million. This estimate includes approximately $60 million of noncash, share-based compensation, net of related capitalization in accordance with the full cost method of accounting for oil and gas properties.

Reduction of Carrying Value of Oil and Gas Properties

We follow the full cost method of accounting for our oil and gas properties described in "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates." Reductions to the carrying value of our oil and gas properties are largely dependent on the success of drilling results and oil and natural gas prices at the end of our quarterly reporting periods. Due to the uncertain nature of future drilling efforts and oil and natural gas prices, we are not able to predict whether we will incur such reductions in 2007.

Interest Expense

Future interest rates and debt outstanding have a significant effect on our interest expense. We can only marginally influence the prices we will receive in 2007 from sales of oil, natural gas and NGLs and the resulting cash flow. These factors increase the margin of error inherent in estimating future outstanding debt balances and related interest expense. Other factors which affect outstanding debt balances and related interest expense, such as the amount and timing of capital expenditures and proceeds from the sale of our assets in Egypt and West Africa, are generally within our control.

Based on the information related to interest expense set forth below, we expect our 2007 interest expense to be between $400 million and $410 million. This estimate assumes no material changes in prevailing interest rates. This estimate also assumes no material changes in our expected level of indebtedness, except for an assumption that our commercial paper will be repaid at the end of the second quarter of 2007.

The interest expense in 2007 related to our fixed-rate debt, including net accretion of related discounts, will be approximately $410 million. This fixed-rate debt removes the uncertainty of future interest rates from some, but not all, of our long-term debt.

Our floating rate debt is comprised of variable-rate commercial paper and one debt instrument which has been converted to floating rate debt through the use of an interest rate swap. Our floating rate debt is summarized in the following table:

DEBT INSTRUMENT	NOTIONAL AMOUNT (IN MILLIONS)	FLOATING RATE
Commercial paper	$ 1,808 (1)	Various (2)
4.375% senior notes due in Oct. 2007	$ 400	LIBOR plus 40 basis points

(1) Represents outstanding balance as of December 31, 2006.
(2) The interest rate is based on a standard index such as the Federal Funds Rate, LIBOR, or the money market rate as found on the commercial paper market. As of December 31, 2006, the average rate on the outstanding balance was 5.37%.

Based on estimates of future LIBOR rates as of December 31, 2006, interest expense on floating rate debt, including net amortization of premiums, is expected to total between $80 million and $90 million in 2007.

Our interest expense totals include payments of facility and agency fees, amortization of debt issuance costs and other miscellaneous items not related to the debt balances outstanding. We expect between $5 million and $15 million of such items to be included in our 2007 interest expense. Also, we expect to capitalize between $95 million and $105 million of interest during 2007.

Effects of Changes in Foreign Currency Rates

Foreign currency gains or losses are not expected to be material in 2007.

Other Income

We estimate that our other income in 2007 will be between $65 million and $85 million.

Historically, we maintained a comprehensive insurance program that included coverage for physical damage to our offshore facilities caused by hurricanes. Our historical insurance program also included substantial business interruption coverage which we are utilizing to recover costs associated with the suspended production related to hurricanes that struck the Gulf of Mexico in the third quarter of 2005.

Based on current estimates of physical damage and the anticipated length of time we will have production suspended, we expect our policy recoveries will exceed repair costs and deductible amounts. This expectation is based upon several variables, including the $467 million received in the third quarter of 2006 as a full settlement of the amount due from our primary insurers. As of December 31, 2006, $154 million of these proceeds had been utilized as reimbursement of past repair costs and deductible amounts. The remaining proceeds of $313 million will be utilized as reimbursement of our anticipated future repair costs. We have not yet received any settlements related to claims filed with our secondary insurers.

Should our total policy recoveries, including the partial settlements already received from our primary insurers, exceed all repair costs and deductible amounts, such excess will be recognized as other income in the statement of operations in the period in which such determination can be made. Based on the most recent estimates of our costs for repairs, we believe that some amount will ultimately be recorded as other income. However, the timing and amount that would be recorded as other income are uncertain. Therefore, the 2007 estimate for other income above does not include any amount related to hurricane proceeds.

Income Taxes

Our financial income tax rate in 2007 will vary materially depending on the actual amount of financial pre-tax earnings. The tax rate for 2007 will be significantly affected by the proportional share of consolidated pre-tax earnings generated by U.S., Canadian and International operations due to the different tax rates of each country. There are certain tax deductions and credits that will have a fixed impact on 2007 income tax expense regardless of the level of pre-tax earnings that are produced.

Given the uncertainty of pre-tax earnings, we expect that our consolidated financial income tax rate in 2007 will be between 20% and 40%. The current income tax rate is expected to be between 15% and 25%. The deferred income tax rate is expected to be between 5% and 15%. Significant changes in estimated capital expenditures, production levels of oil, natural gas and NGLs, the prices of such products, marketing and midstream revenues, or any of the various expense items could materially alter the effect of the aforementioned tax deductions and credits on 2007 financial income tax rates.

Discontinued Operations

As previously discussed, we intend to divest our Egyptian and West African operations in 2007. We expect to complete the sale of Egypt during the first half of 2007 and the sale of West Africa during the third quarter of 2007. The following table shows the estimates for 2007 oil, gas and NGL production as well as the anticipated production and operating expenses associated with these discontinued operations for 2007. These estimates assume the sales of Egypt and West Africa will occur at the end of the second quarter of 2007. Pursuant to accounting rules for discontinued operations, the Egyptian assets will not be subject to DD&A during 2007 and the West African assets will only be subject to DD&A for the first month of 2007.

	EGYPT	WEST AFRICA
Oil production (MMBbls)	1	5
Gas production (Bcf)	—	3
Total production (MMBoe)	1	6
Production and operating expenses (In millions)	$ 11	$ 34
Capital expenditures (In millions)	$ 17	$ 120

Year 2007 Potential Capital Resources, Uses and Liquidity

Capital Expenditures Though we have completed several major property acquisitions in recent years, these transactions are opportunity driven. Thus, we do not "budget," nor can we reasonably predict, the timing or size of such possible acquisitions.

Our capital expenditures budget is based on an expected range of future oil, natural gas and NGL prices as well as the expected costs of the capital additions. Should actual prices received differ materially from our price expectations for our future production, some projects may be accelerated or deferred and, consequently, may increase or decrease total 2007 capital expenditures. In addition, if the actual material or labor costs of the budgeted items vary significantly from the anticipated amounts, actual capital expenditures could vary materially from our estimates.

Given the limitations discussed above, the following table shows expected drilling, development and facilities expenditures by geographic area. Production capital related to proved reserves relates to reserves classified as proved as of year-end 2006. Other production capital includes drilling that does not offset currently productive units and for which there is not a certainty of continued production from a known productive formation. Exploration capital includes exploratory drilling to find and produce oil or gas in previously untested fault blocks or new reservoirs.

	U.S. ONSHORE	U.S. OFFSHORE	CANADA	INTERNATIONAL	TOTAL
			(IN MILLIONS)		
Production capital related to proved reserves	$ 1,170-$ 1,270	$ 80-$ 90	$ 410-$ 450	$ 260-$ 280	$ 1,920-$ 2,090
Other production capital	$ 1,250-$ 1,340	$ 220-$ 230	$ 590-$ 640	$ 15-$ 20	$ 2,075-$ 2,230
Exploration capital	$ 350-$ 380	$ 290-$ 310	$ 160-$ 170	$ 75-$ 85	$ 875-$ 945
Total	$ 2,770-$ 2,990	$ 590-$ 630	$ 1,160-$ 1,260	$ 350-$ 385	$ 4,870-$ 5,265

In addition to the above expenditures for drilling, development and facilities, we expect to spend between $330 million to $370 million on our marketing and midstream assets, which include our oil pipelines, gas processing plants, CO_2 removal facilities and gas transport pipelines. We also expect to capitalize between $245 million and $255 million of G&A expenses in accordance with the full cost method of accounting and to capitalize between $95 million and $105 million of interest. We also expect to pay between $40 million and $50 million for plugging and abandonment charges, and to spend between $135 million and $145 million for other non-oil and gas property fixed assets.

Other Cash Uses Our management expects the policy of paying a quarterly common stock dividend to continue. With the current $0.14 per share quarterly dividend rate and 444 million shares of common stock outstanding as of December 31, 2006, dividends are expected to approximate $250 million. Also, we have $150 million of 6.49% cumulative preferred stock upon which we will pay $10 million of dividends in 2007.

Capital Resources and Liquidity Our estimated 2007 cash uses, including our drilling and development activities, retirement of debt and repurchase of common stock, are expected to be funded primarily through a combination of operating cash flow and proceeds from the sale of our assets in Egypt and West Africa. Any remaining cash uses could be funded by increasing our borrowings under our commercial paper program or with borrowings from the available capacity under our credit facility, which was $408 million at December 31, 2006. The amount of operating cash flow to be generated during 2007 is uncertain due to the factors affecting revenues and expenses as previously cited. However, we expect our combined capital resources to be more than adequate to fund our anticipated capital expenditures and other cash uses for 2007.

If significant other acquisitions or other unplanned capital requirements arise during the year, we could utilize our existing credit facility and/or seek to establish and utilize other sources of financing.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil, gas and NGL prices, interest rates and foreign currency exchange rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil, gas and NGL production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our U.S. and Canadian natural gas and NGL production. Pricing for oil, gas and NGL production has been volatile and unpredictable for several years.

Currently, we are largely accepting the volatility risk that oil, natural gas and NGL prices present. None of our future oil production is subject to price swaps or collars. With regard to our future natural gas production, based on contracts currently in place, we will have approximately 116 MMcf per day of gas production in 2007 that is subject to either fixed-price contracts, swaps, floors or collars. This amount represents approximately 5% of our estimated 2007 gas production (3% of our total Boe production). For the years 2008 through 2011, we have fixed-price physical delivery contracts covering Canadian natural gas production ranging from seven Bcf to 14 Bcf per year. These contracts are not expected to have a material effect on our realized gas prices from 2007 through 2011.

Interest Rate Risk

At December 31, 2006, we had debt outstanding of $7.8 billion. Of this amount, $5.6 billion, or 72%, bears interest at fixed rates averaging 7.3%. Additionally, we had $1.8 billion of outstanding commercial paper bearing interest at floating rates which averaged 5.37% at December 31, 2006. The remaining debt consists of $400 million 4.375% senior notes due in October of 2007. Through the use of an interest rate swap, this fixed-rate debt has been converted to floating-rate debt bearing interest equal to LIBOR plus 40 basis points.

We use a sensitivity analysis technique to evaluate the hypothetical effect that changes in interest rates may have on the fair value of any outstanding interest rate swap instruments. At December 31, 2006, a 10% increase in the underlying interest rates would have decreased the fair value of our interest rate swap by $2 million.

The above sensitivity analysis for interest rate risk excludes accounts receivable, accounts payable and accrued liabilities because of the short-term maturity of such instruments.

Foreign Currency Risk

Our net assets, net earnings and cash flows from our Canadian subsidiaries are based on the U.S. dollar equivalent of such amounts measured in the Canadian dollar functional currency. Assets and liabilities of the Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using the average exchange rate during the reporting period. A 10% unfavorable change in the Canadian-to-U.S. dollar exchange rate would not materially impact our December 31, 2006 balance sheet.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Devon Energy Corporation:

We have audited the accompanying consolidated balance sheets of Devon Energy Corporation and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of operations, comprehensive income, stockholders' equity and cash flows for each of the years in the three-year period ended December 31, 2006. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Devon Energy Corporation and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As described in Note 1 to the consolidated financial statements, as of January 1, 2006, the Company adopted Statements of Financial Accounting Standards No. 123(R), *Share-Based Payment*, and as of December 31, 2006 the Company adopted the balance sheet recognition provisions of Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106, and 132(R).*

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Devon Energy Corporation's internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 26, 2007 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

Oklahoma City, Oklahoma
February 26, 2007

Management's Annual Report on Internal Control Over Financial Reporting

Devon's management is responsible for establishing and maintaining adequate internal control over financial reporting for Devon, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Under the supervision and with the participation of Devon's management, including our principal executive and principal financial officers, Devon conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Framework"). Based on this evaluation under the COSO Framework which was completed on February 12, 2007, management concluded that its internal control over financial reporting was effective as of December 31, 2006.

Management's assessment of the effectiveness of Devon's internal control over financial reporting as of December 31, 2006 has been audited by KPMG LLP, an independent registered public accounting firm who audited Devon's consolidated financial statements as of and for the year ended December 31, 2006, as stated in their report which is included herein.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Devon Energy Corporation:

We have audited management's assessment, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting that Devon Energy Corporation maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Devon Energy Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that Devon Energy Corporation maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, Devon Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Devon Energy Corporation and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of operations, comprehensive income, stockholders' equity and cash flows for each of the years in the three-year period ended December 31, 2006, and our report dated February 26, 2007 expressed an unqualified opinion on those consolidated financial statements. Our report refers to a change in the method of accounting for share-based payments and a change in the balance sheet recognition of defined benefit pension and other postretirement benefit plans.

KPMG LLP

Oklahoma City, Oklahoma
February 26, 2007

Consolidated Balance Sheets

DEVON ENERGY CORPORATION AND SUBSIDIARIES

DECEMBER 31, (IN MILLIONS, EXCEPT SHARE DATA)		2006	2005
ASSETS:			
Current assets:			
Cash and cash equivalents	$	739	1,593
Short-term investments		574	680
Accounts receivable		1,393	1,565
Deferred income taxes		102	158
Current assets held for sale		81	66
Other current assets		323	144
Total current assets		3,212	4,206
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($3,674 and $2,704 excluded from amortization in 2006 and 2005, respectively)		41,889	33,824
Less accumulated depreciation, depletion and amortization		17,294	14,913
		24,595	18,911
Investment in Chevron Corporation common stock, at fair value		1,043	805
Goodwill		5,706	5,705
Assets held for sale		185	217
Other assets		322	429
Total assets	$	35,063	30,273
LIABILITIES AND STOCKHOLDERS' EQUITY:			
Current liabilities:			
Accounts payable – trade	$	1,190	928
Revenues and royalties due to others		529	666
Income taxes payable		197	293
Short-term debt		2,205	662
Accrued interest payable		114	127
Fair value of derivative financial instruments		6	18
Current portion of asset retirement obligation		61	50
Current liabilities associated with assets held for sale		5	19
Accrued expenses and other current liabilities		338	171
Total current liabilities		4,645	2,934
Debentures exchangeable into shares of Chevron Corporation common stock		727	709
Other long-term debt		4,841	5,248
Fair value of derivative financial instruments		302	125
Asset retirement obligation		833	610
Liabilities associated with assets held for sale		25	40
Other liabilities		598	371
Deferred income taxes		5,650	5,374
Stockholders' equity:			
Preferred stock of $1.00 par value. Authorized 4,500,000 shares; issued 1,500,000 ($150 million aggregate liquidation value)		1	1
Common stock of $0.10 par value. Authorized 800,000,000 shares; issued 444,040,000 in 2006 and 443,488,000 in 2005		44	44
Additional paid-in capital		6,840	6,928
Retained earnings		9,114	6,477
Accumulated other comprehensive income		1,444	1,414
Treasury stock, at cost: 11,000 shares in 2006 and 37,000 shares in 2005		(1)	(2)
Total stockholders' equity		17,442	14,862
Commitments and contingencies (Note 8)			
Total liabilities and stockholders' equity	$	35,063	30,273

See accompanying notes to consolidated financial statements.

Consolidated Statements of Operations

DEVON ENERGY CORPORATION AND SUBSIDIARIES

YEAR ENDED DECEMBER 31, (IN MILLIONS, EXCEPT PER SHARE AMOUNTS)		2006	2005	2004
REVENUES:				
Oil sales	$	3,205	2,359	2,099
Gas sales		4,932	5,784	4,732
NGL sales		749	687	554
Marketing and midstream revenues		1,692	1,792	1,701
Total revenues		10,578	10,622	9,086
EXPENSES AND OTHER INCOME, NET:				
Lease operating expenses		1,488	1,324	1,259
Production taxes		341	335	255
Marketing and midstream operating costs and expenses		1,244	1,342	1,339
Depreciation, depletion and amortization of oil and gas properties		2,266	1,981	2,077
Depreciation and amortization of non-oil and gas properties		176	160	148
Accretion of asset retirement obligation		49	43	44
General and administrative expenses		397	291	277
Interest expense		421	533	475
Change in fair value of derivative financial instruments		178	94	62
Reduction of carrying value of oil and gas properties		121	212	—
Other income, net		(115)	(198)	(126)
Total expenses and other income, net		6,566	6,117	5,810
Earnings from continuing operations before income tax expense		4,012	4,505	3,276
INCOME TAX EXPENSE:				
Current		819	1,218	725
Deferred		370	388	370
Total income tax expense		1,189	1,606	1,095
Earnings from continuing operations		2,823	2,899	2,181
DISCONTINUED OPERATIONS:				
Earnings from discontinued operations before income taxes		22	46	17
Income tax (benefit) expense		(1)	15	12
Earnings from discontinued operations		23	31	5
Net earnings		2,846	2,930	2,186
Preferred stock dividends		10	10	10
Net earnings applicable to common stockholders	$	2,836	2,920	2,176
BASIC NET EARNINGS PER SHARE:				
Earnings from continuing operations	$	6.37	6.31	4.50
Earnings from discontinued operations		0.05	0.07	0.01
Net earnings	$	6.42	6.38	4.51
DILUTED NET EARNINGS PER SHARE:				
Earnings from continuing operations	$	6.29	6.19	4.37
Earnings from discontinued operations		0.05	0.07	0.01
Net earnings	$	6.34	6.26	4.38
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
Basic		442	458	482
Diluted		448	470	499

See accompanying notes to consolidated financial statements.

Consolidated Statements of Comprehensive Income

DEVON ENERGY CORPORATION AND SUBSIDIARIES

YEAR ENDED DECEMBER 31, (IN MILLIONS)		2006	2005	2004
Net earnings	$	2,846	2,930	2,186
FOREIGN CURRENCY TRANSLATION:				
Change in cumulative translation adjustment		(25)	181	426
Income taxes		28	(19)	(38)
Total		3	162	388
DERIVATIVE FINANCIAL INSTRUMENTS:				
Unrealized change in fair value		—	(255)	(848)
Reclassification adjustment for realized (gains) losses included in net earnings		(2)	685	635
Income taxes		—	(141)	62
Total		(2)	289	(151)
PENSION AND POSTRETIREMENT BENEFIT PLANS:				
Change in additional minimum pension liability		30	(8)	61
Income taxes		(13)	3	(22)
Total		17	(5)	39
INVESTMENT IN CHEVRON CORPORATION COMMON STOCK:				
Unrealized holding gain		238	60	132
Income taxes		(86)	(22)	(47)
Total		152	38	85
Other comprehensive income, net of tax		170	484	361
Comprehensive income	$	3,016	3,414	2,547

See accompanying notes to consolidated financial statements.

Consolidated Statements of Stockholders' Equity

DEVON ENERGY CORPORATION AND SUBSIDIARIES

(IN MILLIONS)	PREFERRED STOCK	COMMON STOCK SHARES	COMMON STOCK AMOUNT	ADDITIONAL PAID-IN CAPITAL	RETAINED EARNINGS	ACCUMULATED OTHER COMPREHENSIVE INCOME	TREASURY STOCK	TOTAL STOCKHOLDERS' EQUITY
BALANCE AS OF DECEMBER 31, 2003	$ 1	472	$ 47	9,011	1,614	569	(186)	11,056
Net earnings	—	—	—	—	2,186	—	—	2,186
Other comprehensive income	—	—	—	—	—	361	—	361
Stock option exercises	—	13	1	267	—	—	(21)	247
Restricted stock grants, net of cancellations	—	2	—	—	—	—	—	—
Common stock repurchased	—	(5)	—	—	—	—	(190)	(190)
Common stock retired	—	—	—	(341)	—	—	341	—
Conversion of subsidiary preferred stock	—	2	—	—	—	—	56	56
Common stock dividends	—	—	—	—	(97)	—	—	(97)
Preferred stock dividends	—	—	—	—	(10)	—	—	(10)
Share-based compensation	—	—	—	11	—	—	—	11
Excess tax benefits on share-based compensation	—	—	—	54	—	—	—	54
BALANCE AS OF DECEMBER 31, 2004	1	484	48	9,002	3,693	930	—	13,674
Net earnings	—	—	—	—	2,930	—	—	2,930
Other comprehensive income	—	—	—	—	—	484	—	484
Stock option exercises	—	5	—	124	—	—	—	124
Restricted stock grants, net of cancellations	—	1	—	—	—	—	—	—
Common stock repurchased	—	(47)	—	—	—	—	(2,275)	(2,275)
Common stock retired	—	—	(4)	(2,269)	—	—	2,273	—
Common stock dividends	—	—	—	—	(136)	—	—	(136)
Preferred stock dividends	—	—	—	—	(10)	—	—	(10)
Share-based compensation	—	—	—	27	—	—	—	27
Excess tax benefits on share-based compensation	—	—	—	44	—	—	—	44
BALANCE AS OF DECEMBER 31, 2005	1	443	44	6,928	6,477	1,414	(2)	14,862
Net earnings	—	—	—	—	2,846	—	—	2,846
Other comprehensive income	—	—	—	—	—	170	—	170
Adoption of FASB Statement No. 158 (see Note 6)	—	—	—	—	—	(140)	—	(140)
Stock option exercises	—	3	—	73	—	—	—	73
Restricted stock grants, net of cancellations	—	2	—	(3)	—	—	—	(3)
Common stock repurchased	—	(4)	—	—	—	—	(277)	(277)
Common stock retired	—	—	—	(278)	—	—	278	—
Common stock dividends	—	—	—	—	(199)	—	—	(199)
Preferred stock dividends	—	—	—	—	(10)	—	—	(10)
Share-based compensation	—	—	—	84	—	—	—	84
Excess tax benefits on share-based compensation	—	—	—	36	—	—	—	36
BALANCE AS OF DECEMBER 31, 2006	$ 1	444	$ 44	6,840	9,114	1,444	(1)	17,442

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows

DEVON ENERGY CORPORATION AND SUBSIDIARIES

YEAR ENDED DECEMBER 31, (IN MILLIONS)	2006	2005	2004
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net earnings	$ 2,846	2,930	2,186
Less earnings from discontinued operations, net of tax	(23)	(31)	(5)
Adjustments to reconcile net earnings from continuing operations to net cash provided by operating activities:			
Depreciation, depletion and amortization	2,442	2,141	2,225
Deferred income tax expense	370	388	370
Net gain on sales of non-oil and gas property and equipment	(5)	(150)	(34)
Reduction of carrying value of oil and gas properties	121	212	—
Other noncash charges	270	128	110
Changes in assets and liabilities:			
(Increase) decrease in:			
Accounts receivable	212	(279)	(318)
Other current assets	(37)	(17)	(18)
Long-term other assets	(66)	48	(93)
Increase (decrease) in:			
Accounts payable	(183)	255	189
Income taxes payable	(231)	69	208
Debt, including current maturities	—	(67)	16
Other current liabilities	78	(34)	(28)
Long-term other liabilities	142	(79)	(19)
Cash provided by operating activities – continuing operations	5,936	5,514	4,789
Cash provided by operating activities – discontinued operations	57	98	27
Net cash provided by operating activities	5,993	5,612	4,816
CASH FLOWS FROM INVESTING ACTIVITIES:			
Proceeds from sales of property and equipment	40	2,151	95
Capital expenditures	(7,551)	(4,026)	(3,058)
Purchases of short-term investments	(2,395)	(4,020)	(3,215)
Sales of short-term investments	2,501	4,307	2,589
Cash used in investing activities – continuing operations	(7,405)	(1,588)	(3,589)
Cash used in investing activities – discontinued operations	(44)	(64)	(45)
Net cash used in investing activities	(7,449)	(1,652)	(3,634)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net commercial paper borrowings, net of issuance costs	1,808	—	—
Debt repayments, including current maturities	(862)	(1,258)	(973)
Proceeds from stock option exercises	73	124	268
Repurchases of common stock	(253)	(2,263)	(189)
Excess tax benefits related to share-based compensation	36	—	—
Dividends paid on common stock	(199)	(136)	(97)
Dividends paid on preferred stock	(10)	(10)	(10)
Net cash provided by (used in) financing activities	593	(3,543)	(1,001)
Effect of exchange rate changes on cash	13	37	39
Net (decrease) increase in cash and cash equivalents	(850)	454	220
Cash and cash equivalents at beginning of year (including cash related to assets held for sale)	1,606	1,152	932
Cash and cash equivalents at end of year (including cash related to assets held for sale)	$ 756	1,606	1,152
SUPPLEMENTARY CASH FLOW DATA:			
Interest paid	$ 464	663	474
Income taxes paid	$ 960	1,092	477

See accompanying notes to consolidated financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Accounting policies used by Devon Energy Corporation and subsidiaries ("Devon") reflect industry practices and conform to accounting principles generally accepted in the United States of America. The more significant of such policies are briefly discussed below.

Nature of Business and Principles of Consolidation

Devon is engaged primarily in oil and gas exploration, development and production, and the acquisition of properties. Such activities in the United States are concentrated in the following geographic areas:

- The Mid-Continent area of the central and southern United States, principally in north and east Texas and Oklahoma;
- The Permian Basin within Texas and New Mexico;
- The Rocky Mountains area of the United States stretching from the Canadian border into northern New Mexico;
- The offshore areas of the Gulf of Mexico; and
- The onshore areas of the Gulf Coast, principally in south Texas and south Louisiana.

Devon's Canadian activities are located primarily in the Western Canadian Sedimentary Basin. Devon's international activities — outside of North America — are located primarily in Azerbaijan, Brazil, China and various countries in West Africa. On January 23, 2007, Devon announced its plans to divest its West African operations. See Note 13.

Devon also has marketing and midstream operations which are responsible for marketing natural gas, crude oil and NGLs, and constructing and operating pipelines, storage and treating facilities and gas processing plants. These services are performed for Devon as well as for unrelated third parties.

The accounts of Devon's controlled subsidiaries are included in the accompanying consolidated financial statements. All significant intercompany accounts and transactions have been eliminated in consolidation.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual amounts could differ from these estimates, and changes in these estimates are recorded when known. Significant items subject to such estimates and assumptions include estimates of proved reserves and related present value estimates of future net revenue, the carrying value of oil and gas properties, goodwill impairment assessment, asset retirement obligations, income taxes, valuation of derivative instruments, obligations related to employee benefits and legal and environmental risks and exposures.

Property and Equipment

Devon follows the full cost method of accounting for its oil and gas properties. Accordingly, all costs incidental to the acquisition, exploration and development of oil and gas properties, including costs of undeveloped leasehold, dry holes and leasehold equipment, are capitalized. Internal costs incurred that are directly identified with acquisition, exploration and development activities undertaken by Devon for its own account, and which are not related to production, general corporate overhead or similar activities, are also capitalized. Interest costs incurred and attributable to unproved oil and gas properties under current evaluation and major development projects of oil and gas properties are also capitalized. All costs related to production activities, including workover costs incurred solely to maintain or increase levels of production from an existing completion interval, are charged to expense as incurred.

Under the full cost method of accounting, the net book value of oil and gas properties, less related deferred income taxes, may not exceed a calculated "ceiling." The ceiling limitation is the estimated after-tax future net revenues, discounted at 10% per annum, from proved oil, natural gas and NGL reserves plus the cost of properties not subject to amortization. Estimated future net revenues exclude future cash outflows associated with settling asset retirement obligations included in the net book value of oil and gas properties. Such limitations are imposed separately on a country-by-country basis and are tested quarterly. In calculating future net revenues, prices and costs used are those as of the end of the appropriate quarterly period. These prices are not changed except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including designated cash flow hedges in place. Devon had no such hedges outstanding at December 31, 2006 or December 31, 2005.

Any excess of the net book value, less related deferred taxes, over the ceiling is written off as an expense. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period.

Capitalized costs are depleted by an equivalent unit-of-production method, converting gas to oil at the ratio of six thousand cubic feet of natural gas to one barrel of oil. Depletion is calculated using the capitalized costs, including estimated asset retirement costs, plus the estimated future expenditures (based on current costs) to be incurred in developing proved reserves, net of estimated salvage values.

Unproved properties are excluded from amortized capitalized costs until it is determined whether or not proved reserves can be assigned to such properties. Devon assesses its unproved properties for impairment quarterly. Significant unproved properties are assessed individually. Costs of insignificant unproved properties are transferred to amortizable costs over average holding periods ranging from three years for onshore properties to seven years for offshore properties.

No gain or loss is recognized upon disposal of oil and gas properties unless such disposal significantly alters the relationship between capitalized costs and proved reserves in a particular country.

Depreciation of midstream pipelines are provided on a units-of-production basis. Depreciation and amortization of other property and equipment, including corporate and other midstream assets and leasehold improvements, are provided using the straight-line method based on estimated useful lives ranging from three to 39 years.

Devon recognizes liabilities for retirement obligations associated with tangible long-lived assets, such as producing well sites, offshore production platforms, and natural gas processing plants when there is a legal obligation associated with the retirement of such assets and the amount can be reasonably estimated. The initial measurement of an asset retirement obligation is recorded as a liability at its fair value, with an offsetting asset retirement cost recorded as an increase to the associated property and equipment on the consolidated balance sheet. If the fair value of a recorded asset retirement obligation changes, a revision is recorded to both the asset retirement obligation and the asset retirement cost. The asset retirement cost is depreciated using a systematic and rational method similar to that used for the associated property and equipment.

Short-Term Investments and Other Marketable Securities

Devon reports its short-term investments and other marketable securities at fair value, except for debt securities in which management has the ability and intent to hold until maturity. At December 31, 2006 and 2005, Devon's short-term investments consisted of $574 million and $680 million, respectively, of auction rate securities classified as available for sale. Although Devon's auction rate securities have contractual maturities of more than 10 years, the underlying interest rates on such securities reset at intervals ranging from seven to 90 days. Therefore, these auction rate securities are priced and subsequently trade as short-term investments because of the interest rate reset feature. As a result, Devon has classified its auction rate securities as short-term investments in the accompanying consolidated balance sheet.

Devon's only other significant investment security is its investment in approximately 14.2 million shares of Chevron Corporation common stock which is reported at fair value. Except for unrealized losses that are determined to be "other than temporary", the tax effected unrealized gain or loss on the investment in Chevron Corporation common stock is recognized in other comprehensive income and reported as a separate component of stockholders' equity.

Goodwill

Goodwill represents the excess of the purchase price of business combinations over the fair value of the net assets acquired and is tested for impairment at least annually. The impairment test requires allocating goodwill and all other assets and liabilities to assigned reporting units. The fair value of each reporting unit is estimated and compared to the net book value of the reporting unit. If the estimated fair value of the reporting unit is less than the net book value, including goodwill, then the goodwill is written down to the implied fair value of the goodwill through a charge to expense. Because quoted market prices are not available for Devon's reporting units, the fair values of the reporting units are estimated based upon several valuation analyses, including comparable companies, comparable transactions and premiums paid. Devon performed annual impairment tests of goodwill in the fourth quarters of 2006, 2005 and 2004. Based on these assessments, no impairment of goodwill was required.

The table below provides a summary of Devon's goodwill, by assigned reporting unit, as of December 31, 2006 and 2005:

	DECEMBER 31,	
	2006	2005
	(IN MILLIONS)	
United States	$ 3,053	3,056
Canada	2,585	2,581
International	68	68
Total	$ 5,706	5,705

Revenue Recognition and Gas Balancing

Oil, gas and NGL revenues are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred and collectibility of the revenue is probable. Delivery occurs and title is transferred when production has been delivered to a pipeline or truck or a tanker lifting has occurred. Cash received relating to future production is deferred and recognized when all revenue recognition criteria are met. Taxes assessed by governmental authorities on oil, gas and NGL revenues are presented separately from such revenues as production taxes in the statement of operations.

Devon follows the sales method of accounting for gas production imbalances. The volumes of gas sold may differ from the volumes to which Devon is entitled based on its interests in the properties. These differences create imbalances that are recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the under produced owner to recoup its entitled share through production. If an imbalance exists at the time the wells' reserves are depleted, settlements are made among the joint interest owners under a variety of arrangements. The liability is priced based on current market prices. No receivables are recorded for those wells where Devon has taken less than its share of production unless all revenue recognition criteria are met.

Marketing and midstream revenues are recorded at the time products are sold or services are provided to third parties at a fixed or determinable price, delivery or performance has occurred, title has transferred and collectibility of the revenue is probable. Revenues and expenses attributable to Devon's gas and NGL purchase and processing contracts are reported on a gross basis since Devon takes title to the products and has risks and rewards of ownership. The gas purchased under these contracts is processed in Devon-owned plants.

Major Purchasers

During 2006, revenues received from ExxonMobil and its affiliates were $1.1 billion, or 10% of Devon's consolidated revenues. No purchaser accounted for over 10% of Devon's revenues in 2005 or 2004.

Derivative Instruments

The majority of Devon's derivative instruments consist of commodity financial instruments used to manage Devon's cash flow exposure to oil and gas price volatility. Devon has also entered into interest rate swaps to manage its exposure to interest rate volatility. The interest rate swaps mitigate either the cash flow effects of interest rate fluctuations on interest expense for variable-rate debt instruments, or the fair value effects of interest rate fluctuations on fixed-rate debt. Devon also has an embedded option derivative related to the fair value of its debentures exchangeable into shares of Chevron Corporation common stock.

All derivatives are recognized at their current fair value as fair value of derivative financial instruments on the balance sheet. Changes in the fair value of derivative financial instruments are recorded in the statement of operations unless specific hedge accounting criteria are met. If such criteria are met for cash flow hedges, the effective portion of the change in the fair value is recorded directly to accumulated other comprehensive income, a component of stockholders' equity, until the hedged transaction occurs. The ineffective portion of the change in fair value is recorded in the statement of operations. If such criteria are met for fair value hedges, the change in the fair value is recorded in the statement of operations with an offsetting amount recorded for the change in fair value of the hedged item.

A derivative instrument qualifies for hedge accounting treatment if Devon designates the instrument as such on the date the derivative contract is entered into or the date of an acquisition or business combination which includes derivative contracts. Additionally, Devon must document the relationship between the hedging instrument and hedged item, as well as the risk-management objective and strategy for undertaking the instrument. Devon must also assess, both at the instrument's inception and on an ongoing basis, whether the derivative is highly effective in offsetting the change in cash flow of the hedged item.

During 2006, Devon entered into and acquired certain commodity derivative instruments. For such instruments, Devon chose not to meet the necessary criteria to qualify these derivative instruments for hedge accounting treatment. Therefore, Devon recorded a $37 million gain in gas sales in the statement of operations for the change in fair value related to these instruments.

The following table presents the components of the 2006, 2005 and 2004 change in fair value of derivative financial instruments presented in the accompanying statement of operations. Significant items are discussed in more detail following the table.

		2006	2005	2004
			(IN MILLIONS)	
Option embedded in exchangeable debentures	$	181	54	58
Non-qualifying commodity hedges		—	39	—
Ineffectiveness of commodity hedges		—	5	5
Interest rate swaps		(3)	(4)	(1)
Total change in fair value of derivative financial instruments	$	178	94	62

The change in the fair value of the embedded option relates to the debentures exchangeable into shares of Chevron Corporation common stock. These expenses were caused primarily by increases in the price of Chevron Corporation's common stock.

During 2005 and 2004, Devon had a number of commodity derivative instruments that qualified for hedge accounting treatment as described above. During 2005, certain of these derivatives ceased to qualify for hedge accounting treatment. In the third quarter of 2005, certain oil derivatives ceased to qualify for hedge accounting primarily as a result of deferred production caused by hurricanes in the Gulf of Mexico. Because these contracts no longer qualified for hedge accounting, Devon recognized $39 million in losses as change in fair value of derivative financial instruments in the accompanying 2005 statement of operations.

In addition to the changes in fair value of non-qualifying commodity hedges presented in the table above, Devon also recognized in 2005 a $55 million loss related to certain oil hedges that no longer qualified for hedge accounting due to the effect of the 2005 property divestiture program. These commodity instruments related to 5,000 barrels per day of U.S. oil production and 3,000 barrels per day of Canadian oil production from properties that were sold as part of Devon's divestiture program. This loss is presented in other income in the accompanying 2005 statement of operations. During 2004, no derivatives ceased to qualify for hedge accounting.

In addition to the changes in fair value of Devon's interest rate swaps presented in the table above, settlements on these interest rate swaps increased interest expense by $15 million and $12 million in 2006 and 2005, respectively, and decreased interest expense $18 million in 2004.

The following table presents the balances of Devon's accumulated net gain (loss) on cash flow hedges included in accumulated other comprehensive income.

		(IN MILLIONS)
December 31, 2003	$	(135)
December 31, 2004	$	(286)
December 31, 2005	$	3
December 31, 2006	$	1

By using derivative instruments to hedge exposures to changes in commodity prices and interest rates, Devon exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. To mitigate this risk, the hedging instruments are placed with counterparties that Devon believes are minimal credit risks. It is Devon's policy to enter into derivative contracts only with investment grade rated counterparties deemed by management to be competent and competitive market makers.

Market risk is the change in the value of a derivative instrument that results from a change in commodity prices, interest rates or other relevant underlyings. The market risk associated with commodity price and interest rate contracts is managed by establishing and monitoring parameters that limit the types and degree of market risk that may be undertaken. The oil and gas reference prices upon which the commodity hedging instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by Devon. Devon does not hold or issue derivative instruments for speculative trading purposes.

Stock Options

Effective January 1, 2006, Devon adopted Statement of Financial Accounting Standard No. 123(R), *Share-Based Payment,* ("SFAS No. 123(R)"), using the modified prospective transition method. SFAS No. 123(R) requires equity-classified, share-based payments to employees, including grants of employee stock options, to be valued at fair value on the date of grant and to be expensed over the applicable vesting period. Under the modified prospective transition method, share-based awards granted or modified on or after January 1, 2006, are recognized in compensation expense over the applicable vesting period. Also, any previously granted awards that were not fully vested as of January 1, 2006 are recognized as compensation expense over the remaining vesting period. No retroactive or cumulative effect adjustments were required upon Devon's adoption of SFAS No. 123(R).

Prior to adopting SFAS No. 123(R), Devon accounted for its fixed-plan employee stock options using the intrinsic-value based method prescribed by Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees,* ("APB No. 25") and related interpretations. This method required compensation expense to be recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price.

Had the fair value provisions of SFAS No. 123(R) been applied in 2005 and 2004, Devon's net earnings and net earnings per share would have differed from the amounts actually reported as shown in the following table.

	YEAR ENDED DECEMBER 31, 2005	2004
	(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)	
Net earnings available to common stockholders, as reported	$ 2,920	2,176
Add share-based employee compensation expense included in reported net earnings, net of related tax expense	18	7
Deduct total share-based employee compensation expense determined under fair value based method for all awards (see Note 9), net of related tax expense	(44)	(31)
Net earnings available to common stockholders, pro forma	$ 2,894	2,152
Net earnings per share available to common stockholders:		
As reported:		
Basic	$ 6.38	4.51
Diluted	$ 6.26	4.38
Pro forma:		
Basic	$ 6.32	4.46
Diluted	$ 6.21	4.33

As a result of adopting SFAS No. 123(R), Devon's 2006 earnings from continuing operations before income tax expense was $26 million lower than if Devon had continued to account for share-based compensation under APB No. 25. Additionally, 2006 earnings from continuing operations and net earnings were both $17 million lower. The related 2006 basic and diluted earnings per share amounts were both approximately $0.04 per share lower. Prior to the adoption of SFAS No. 123(R), Devon presented all tax benefits of deductions resulting from the exercise of stock options as operating cash inflows in the statement of cash flows. SFAS No. 123(R) requires the cash inflows resulting from tax deductions in excess of the compensation expense recognized for those stock options ("excess tax benefits") to be classified as financing cash inflows. As required by SFAS No. 123(R), Devon recognized $36 million of excess tax benefits as financing cash inflows for 2006. In 2005 and 2004, excess tax benefits of $44 million and $54 million, respectively, were classified as operating cash inflows.

Income Taxes

Devon accounts for income taxes using the asset and liability method, whereby deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases, as well as the future tax consequences attributable to the future utilization of existing tax net operating loss and other types of carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. At December 31, 2006, undistributed earnings of foreign subsidiaries were determined to be permanently reinvested. Therefore, no U.S. deferred income taxes were provided on such amounts at December 31, 2006. If it becomes apparent that some or all of the undistributed earnings will be distributed, Devon would then record taxes on those earnings.

General and Administrative Expenses

General and administrative expenses are reported net of amounts reimbursed by working interest owners of the oil and gas properties operated by Devon and net of amounts capitalized pursuant to the full cost method of accounting.

Net Earnings Per Common Share

Basic earnings per share is computed by dividing income available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted earnings per share, as calculated using the treasury stock method, reflects the potential dilution that could occur if Devon's dilutive outstanding stock options were exercised. For 2005 and 2004, the calculation of diluted shares also assumed that Devon's previously outstanding zero coupon convertible senior debentures were converted to common stock.

The following table reconciles earnings from continuing operations and common shares outstanding used in the calculations of basic and diluted earnings per share for 2006, 2005 and 2004.

	NET EARNINGS APPLICABLE TO COMMON STOCKHOLDERS	WEIGHTED AVERAGE COMMON SHARES OUTSTANDING	NET EARNINGS PER SHARE
	(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)		
YEAR ENDED DECEMBER 31, 2006:			
Earnings from continuing operations	$ 2,823		
Less preferred stock dividends	(10)		
Basic earnings per share	2,813	442	$ 6.37
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	—	6	
Diluted earnings per share	$ 2,813	448	$ 6.29
YEAR ENDED DECEMBER 31, 2005:			
Earnings from continuing operations	$ 2,899		
Less preferred stock dividends	(10)		
Basic earnings per share	2,889	458	$ 6.31
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	—	8	
Dilutive effect of potential common shares issuable upon conversion of senior convertible debentures (increase in net earnings is net of income tax expense of $14 million) (1)	24	4	
Diluted earnings per share	$ 2,913	470	$ 6.19
YEAR ENDED DECEMBER 31, 2004:			
Earnings from continuing operations	$ 2,181		
Less preferred stock dividends	(10)		
Basic earnings per share	2,171	482	$ 4.50
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	—	8	
Dilutive effect of potential common shares issuable upon conversion of senior convertible debentures (increase in net earnings is net of income tax expense of $6 million)	10	9	
Diluted earnings per share	$ 2,181	499	$ 4.37

(1) The senior convertible debentures were retired in June 2005 prior to their stated maturity.

Certain options to purchase shares of Devon's common stock were excluded from the dilution calculations because the options were antidilutive. These excluded options totaled 3 million, 0.2 million and 4 million in 2006, 2005 and 2004, respectively.

Foreign Currency Translation Adjustments

The U.S. dollar is the functional currency for Devon's consolidated operations except its Canadian subsidiaries which use the Canadian dollar as the functional currency. Therefore, the assets and liabilities of Devon's Canadian subsidiaries are translated into U.S. dollars based on the current exchange rate in effect at the balance sheet dates. Canadian income and expenses are translated at average rates for the periods presented. Translation adjustments have no effect on net income and are included in accumulated other comprehensive income in stockholders' equity. The following table presents the balances of Devon's cumulative translation adjustments included in accumulated other comprehensive income.

	(IN MILLIONS)
December 31, 2003	$ 666
December 31, 2004	$ 1,054
December 31, 2005	$ 1,216
December 31, 2006	$ 1,219

Statements of Cash Flows

For purposes of the consolidated statements of cash flows, Devon considers all highly liquid investments with original contractual maturities of three months or less to be cash equivalents.

Commitments and Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Environmental expenditures are expensed or capitalized in accordance with accounting principles generally accepted in the United States of America. Liabilities for these expenditures are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated. Reference is made to Note 8 for a discussion of amounts recorded for these liabilities.

Recently Issued Accounting Standards Not Yet Adopted

In June 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109*. Interpretation No. 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes*. This Interpretation is effective for fiscal years beginning after December 15, 2006, and Devon will adopt it in the first quarter of 2007. Devon does not expect the adoption of Interpretation No. 48 to have a material impact on its financial statements and related disclosures.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, *Fair Value Measurements*. Statement No. 157 provides a common definition of fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. However, this Statement does not require any new fair value measurements. Statement No. 157 is effective for fiscal years beginning after November 15, 2007. Devon is currently assessing the effect, if any, the adoption of Statement No. 157 will have on its financial statements and related disclosures.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106, and 132(R).* Statement No. 158 requires the recognition of the overfunded or underfunded status of a defined benefit postretirement plan in the balance sheet. Devon adopted this recognition requirement as of December 31, 2006. The effects of this adoption are summarized in Note 6. Statement No. 158 also requires the measurement of plan assets and benefit obligations as of the date of the employer's fiscal year-end. The Statement provides two alternatives to transition to a fiscal year-end measurement date. This measurement requirement is effective for fiscal years ending after December 15, 2008. Devon has not yet adopted this measurement requirement, but Devon does not expect such adoption to have a material effect on its results of operations, financial condition, liquidity or compliance with debt covenants.

In February 2007, the FASB issued Statement of Financial Accounting Standards No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115*. Statement No. 159 permits entities to choose to measure certain financial instruments and other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Unrealized gains and losses on any items for which Devon elects the fair value measurement option would be reported in earnings. Statement No. 159 is effective for fiscal years beginning after November 15, 2007. However, early adoption is permitted for fiscal years beginning on or before November 15, 2007, provided Devon also elects to apply the provisions of Statement No. 157, *Fair Value Measurements*, at the same time. Devon is currently assessing the effect, if any, the adoption of Statement No. 159 will have on its financial statements and related disclosures.

2. ACCOUNTS RECEIVABLE

The components of accounts receivable include the following:

		December 31, 2006	December 31, 2005
		(In millions)	
Oil, gas and NGL revenue	$	1,020	1,113
Joint interest billings		209	206
Marketing and midstream revenue		138	173
Other		31	78
		1,398	1,570
Allowance for doubtful accounts		(5)	(5)
Net accounts receivable	$	1,393	1,565

3. PROPERTY AND EQUIPMENT AND ASSET RETIREMENT OBLIGATIONS

Property and equipment included the following:

		December 31, 2006	December 31, 2005
		(In millions)	
Oil and gas properties:			
Subject to amortization	$	35,798	29,257
Not subject to amortization		3,674	2,704
Accumulated depreciation, depletion and amortization		(16,610)	(14,398)
Net oil and gas properties		22,862	17,563
Other property and equipment		2,417	1,863
Accumulated depreciation and amortization		(684)	(515)
Net other property and equipment		1,733	1,348
Property and equipment, net of accumulated depreciation, depletion and amortization	$	24,595	18,911

The costs not subject to amortization relate to unproved properties which are excluded from amortized capital costs until it is determined whether or not proved reserves can be assigned to such properties. The excluded properties are assessed for impairment quarterly. Subject to industry conditions, evaluation of most of these properties, and the inclusion of their costs in the amortized capital costs is expected to be completed within five years.

The following is a summary of Devon's oil and gas properties not subject to amortization as of December 31, 2006:

		Costs Incurred In 2006	2005	2004	Prior to 2004	Total
				(In millions)		
Acquisition costs	$	1,357	296	119	691	2,463
Exploration costs		423	239	86	62	810
Development costs		130	19	—	39	188
Capitalized interest		70	56	52	35	213
Total oil and gas properties not subject to amortization	$	1,980	610	257	827	3,674

At December 31, 2006, Devon's investment in countries where proved reserves have not been established was $61 million, consisting of $56 million in Nigeria and $5 million in Ghana.

Chief Acquisition

On June 29, 2006, Devon acquired the oil and gas assets of privately-owned Chief Holdings LLC ("Chief"). Devon paid $2.0 billion in cash and assumed approximately $0.2 billion of net liabilities in the transaction for a total purchase price of $2.2 billion. Devon funded the acquisition price, and the immediate retirement of $180 million of assumed debt, with $718 million of cash on hand and approximately $1.4 billion of borrowings issued under its commercial paper program. The acquired oil and gas properties consist of 99.7 MMBoe (unaudited) of proved reserves and leasehold totaling 169,000 net acres located in the Barnett Shale area of north Texas. Devon allocated approximately $1.0 billion of the purchase price to proved reserves and approximately $1.2 billion to unproved properties.

Property Divestitures

During 2005, Devon divested certain non-core oil and gas properties in the offshore Gulf of Mexico and onshore in the United States and Canada. From these sales, Devon received $2.0 billion of gross proceeds. After-tax, the proceeds were approximately $1.8 billion. Certain information regarding these sales is included in the following table.

	UNITED STATES	CANADA	TOTAL
		(IN MILLIONS)	
Gross proceeds	$ 966	1,029	1,995
After-tax proceeds	$ 786	1,027	1,813
Asset retirement obligations assumed by purchasers	$ 160	39	199
Reserves sold (MMBoe) (unaudited)	89	87	176

Under full cost accounting rules, a gain or loss on the sale or other disposition of oil and gas properties is not recognized unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. Because the 2005 divestitures did not significantly alter such relationship, Devon did not recognize a gain or loss on these divestitures. Therefore, the proceeds from these transactions were recognized as an adjustment of capitalized costs in the respective cost centers.

On November 14, 2006, Devon announced that it intends to divest its operations in Egypt. Also, on January 23, 2007, Devon announced that it intends to divest its operations in West Africa. See Note 13 for more discussion regarding these planned divestitures.

Asset Retirement Obligations

Following is a reconciliation of the asset retirement obligation for the years ended December 31, 2006 and 2005.

	YEAR ENDED DECEMBER 31,	
	2006	2005
	(IN MILLIONS)	
Asset retirement obligation as of beginning of year	$ 660	731
Liabilities incurred	102	44
Liabilities settled	(62)	(42)
Liabilities assumed by others	—	(199)
Revision of estimated obligation	149	76
Accretion expense on discounted obligation	49	43
Foreign currency translation adjustment	(4)	7
Asset retirement obligation as of end of year	894	660
Less current portion	61	50
Asset retirement obligation, long-term	$ 833	610

4. DEBT AND RELATED EXPENSES

A summary of Devon's short-term and long-term debt is as follows:

	DECEMBER 31, 2006	DECEMBER 31, 2005
	(IN MILLIONS)	
Commercial paper	$ 1,808	—
Debentures exchangeable into shares of Chevron Corporation common stock:		
4.90% due August 15, 2008	444	444
4.95% due August 15, 2008	316	316
Discount on exchangeable debentures	(33)	(51)
Other debentures and notes:		
2.75% due August 1, 2006	—	500
6.55% due August 2, 2006 ($200 million Canadian)	—	172
4.375% due October 1, 2007	400	400
10.125% due November 15, 2009	177	177
6.875% due September 30, 2011	1,750	1,750
7.25% due October 1, 2011	350	350
8.25% due July 1, 2018	125	125
7.50% due September 15, 2027	150	150
7.875% due September 30, 2031	1,250	1,250
7.95% due April 15, 2032	1,000	1,000
Other	—	3
Fair value adjustment on debt related to interest rate swaps	(5)	(18)
Net premium on other debentures and notes	41	51
	7,773	6,619
Less amount classified as short-term debt	2,205	662
Long-term debt	$ 5,568	5,957

Maturities of short-term and long-term debt as of December 31, 2006, excluding premiums, discounts and the $5 million fair value adjustment, are as follows:

	(IN MILLIONS)
2007	$ 2,208
2008	760
2009	177
2010	—
2011	2,100
2012 and thereafter	2,525
Total	$ 7,770

Credit Facilities with Banks

Devon has a $2.5 billion five-year, syndicated, unsecured revolving line of credit (the "Senior Credit Facility"). The Senior Credit Facility includes a five-year revolving Canadian subfacility in a maximum amount of U.S. $500 million.

The Senior Credit Facility matures on April 7, 2011, and all amounts outstanding will be due and payable at that time unless the maturity is extended. Prior to each April 7 anniversary date, Devon has the option to extend the maturity of the Senior Credit Facility for one year, subject to the approval of the lenders. Devon is working to obtain lender approval to extend the current maturity date of April 7, 2011 to April 7, 2012. If successful, this maturity date extension will be effective on April 7, 2007, provided Devon has not experienced a "material adverse effect," as defined in the Senior Credit Facility agreement, at that date.

Amounts borrowed under the Senior Credit Facility may, at the election of Devon, bear interest at various fixed rate options for periods of up to twelve months. Such rates are generally less than the prime rate. Devon may also elect to borrow at the prime rate. The Senior Credit Facility currently provides for an annual facility fee of $2.3 million that is payable quarterly in arrears.

The agreement governing the Senior Credit Facility contains certain covenants and restrictions, including a maximum allowed debt-to-capitalization ratio of 65% as defined in the agreement. The credit agreement contains definitions of total funded debt and total capitalization that include adjustments to the respective amounts reported in Devon's consolidated financial statements. Per the agreement, total funded debt excludes the debentures that are exchangeable into shares of Chevron Corporation common stock. Also, total capitalization is adjusted to add back noncash financial writedowns such as full cost ceiling property impairments or goodwill impairments. At December 31, 2006, Devon was in compliance with such covenants and restrictions. Devon's debt-to-capitalization ratio at December 31, 2006, as calculated pursuant to the terms of the agreement, was 27.3%.

As of December 31, 2006, there were no borrowings under the Senior Credit Facility. The available capacity under the Senior Credit Facility as of December 31, 2006, net of $284 million of outstanding letters of credit and $1.8 billion of outstanding commercial paper, was approximately $408 million.

Commercial Paper

Devon also has a commercial paper program under which it may borrow up to $2 billion. Borrowings under the commercial paper program reduce available capacity under the Senior Credit Facility on a dollar-for-dollar basis. Commercial paper debt generally has a maturity of between seven to 90 days, although it can have a maturity of up to 365 days, and bears interest at rates agreed to at the time of the borrowing. The interest rate is based on a standard index such as the Federal Funds Rate, LIBOR, or the money market rate as found on the commercial paper market. As of December 31, 2006, Devon had $1.8 billion of commercial paper debt outstanding at an average rate of 5.37%. The $1.8 billion of commercial paper is classified as short-term debt in the accompanying consolidated balance sheet.

Exchangeable Debentures

The exchangeable debentures consist of $444 million of 4.90% debentures and $316 million of 4.95% debentures. The exchangeable debentures were issued on August 3, 1998 and mature August 15, 2008. The exchangeable debentures were callable beginning August 15, 2000, initially at 104.0% of principal and at prices declining to 100.5% of principal on or after August 15, 2007. At December 31, 2006, the call price was 101% of principal. The exchangeable debentures are exchangeable at the option of the holders at any time prior to maturity, unless previously redeemed, for shares of Chevron common stock. In lieu of delivering Chevron common stock to an exchanging debenture holder, Devon may, at its option, pay to such holder an amount of cash equal to the market value of the Chevron common stock. At maturity, holders who have not exercised their exchange rights will receive an amount in cash equal to the principal amount of the debentures.

As of December 31, 2006, Devon beneficially owned approximately 14.2 million shares of Chevron common stock. These shares have been deposited with an exchange agent for possible exchange for the exchangeable debentures. Each $1,000 principal amount of the exchangeable debentures is exchangeable into 18.6566 shares of Chevron common stock, an exchange rate equivalent to $53.60 per share of Chevron stock.

The exchangeable debentures were assumed as part of the 1999 PennzEnergy acquisition. As a result, the fair values of the exchangeable debentures were determined as of August 17, 1999, based on market quotations. In accordance with derivative accounting standards, the total fair value of the debentures was allocated between the interest-bearing debt and the option to exchange Chevron common stock that is embedded in the debentures. Accordingly, a discount was recorded on the debentures and is being accreted using the effective interest method which raised the effective interest rate on the debentures to 7.76%.

Other Debentures and Notes

Following are descriptions of the various other debentures and notes outstanding at December 31, 2006, as listed in the table presented at the beginning of this note.

Ocean Debt In connection with the 2003 Ocean merger, Devon assumed $1.8 billion of debt. The table below summarizes the debt assumed which remains outstanding, the fair value of the debt at April 25, 2003, and the effective interest rate of the debt assumed after determining the fair values of the respective notes using April 25, 2003, market interest rates. The premiums are being amortized using the effective interest method. All of the notes are general unsecured obligations of Devon.

DEBT ASSUMED	FAIR VALUE OF DEBT ASSUMED	EFFECTIVE RATE OF DEBT ASSUMED
	(IN MILLIONS)	
4.375% due October 2007 (principal of $400 million)	$ 410	3.8%
7.250% due October 2011 (principal of $350 million)	$ 406	4.9%
8.250% due July 2018 (principal of $125 million)	$ 147	5.5%
7.500% due September 2027 (principal of $150 million)	$ 169	6.5%

The $400 million 4.375% senior notes due in October of 2007 are subject to a fixed-to-floating interest rate swap. Through the use of this swap, this fixed-rate debt has been converted to floating-rate debt bearing interest equal to LIBOR plus 40 basis points.

10.125% Debentures due November 15, 2009 These debentures were assumed as part of the PennzEnergy acquisition. The fair value of the debentures was determined using August 17, 1999, market interest rates. As a result, a premium was recorded on these debentures which lowered the effective interest rate to 8.9%. The premium is being amortized using the effective interest method.

6.875% Notes due September 30, 2011 and 7.875% Debentures due September 30, 2031 On October 3, 2001, Devon, through Devon Financing Corporation, U.L.C. ("Devon Financing"), sold these notes and debentures which are unsecured and unsubordinated obligations of Devon Financing. Devon has fully and unconditionally guaranteed on an unsecured and unsubordinated basis the obligations of Devon Financing under the debt securities. The proceeds from the issuance of these debt securities were used to fund a portion of the Anderson acquisition.

7.95% Notes due April 15, 2032 On March 25, 2002, Devon sold these notes which are unsecured and unsubordinated obligations of Devon. The net proceeds received, after discounts and issuance costs, were $986 million and were used to retire other indebtedness.

Interest Expense

The following schedule includes the components of interest expense between 2004 and 2006.

		Year Ended December 31,		
		2006	2005	2004
		(In millions)		
Interest based on debt outstanding	$	486	507	513
Capitalized interest		(79)	(70)	(70)
Other interest		14	96	32
Total interest expense	$	421	533	475

Interest based on debt outstanding decreased from 2004 to 2006 primarily due to the net effect of debt repayments during 2005 and 2006 partially offset by the effect of commercial paper borrowings during the last half of 2006.

During 2005, Devon redeemed its $400 million 6.75% notes due March 15, 2011 and its zero coupon convertible senior debentures prior to their scheduled maturity dates. The other interest category in the table above includes $81 million in 2005 related to these early retirements.

During 2004, Devon repaid the balance under its $3 billion term loan credit facility prior to the scheduled repayment date. The other interest category in the table above includes $16 million in 2004 related to this early repayment.

5. FINANCIAL INSTRUMENTS

The following table presents the carrying amounts and estimated fair values of Devon's financial instrument assets (liabilities) at December 31, 2006 and 2005.

		2006		2005	
		Carrying Amount	Fair Value	Carrying Amount	Fair Value
		(In millions)			
Investment in Chevron Corporation common stock	$	1,043	1,043	805	805
Oil and gas price hedge agreements	$	39	39	—	—
Interest rate swap agreements	$	(6)	(6)	(22)	(22)
Embedded option in exchangeable debentures	$	(302)	(302)	(121)	(121)
Debt	$	(7,773)	(8,725)	(6,619)	(7,642)

The following methods and assumptions were used to estimate the fair values of the financial instruments in the above table. The carrying values of cash and cash equivalents, short-term investments, accounts receivable and accounts payable (including income taxes payable and accrued expenses) included in the accompanying consolidated balance sheets approximated fair value at December 31, 2006 and 2005.

Investment in Chevron Corporation common stock The fair value of this investment is based on a quoted market price.

Oil and gas price hedge agreements The fair values of the oil and gas price hedges were based on either (a) an internal discounted cash flow calculation, (b) quotes obtained from the counterparty to the hedge agreement or (c) quotes provided by brokers.

Interest rate swap agreements The fair values of the interest rate swaps are based on internal discounted cash flow calculations, using market quotes of future interest rates, or quotes obtained from counterparties.

Embedded option in exchangeable debentures The fair value of the embedded option is based on a quote obtained from a broker.

Debt The fair values of fixed-rate debt are based on quotes obtained from brokers or by discounting the principal and interest payments at rates available for debt of similar terms and maturity. The fair values of floating-rate debt are estimated to approximate the carrying amounts because the interest rates paid on such debt are generally set for periods of three months or less.

6. RETIREMENT PLANS

Devon has various non-contributory defined benefit pension plans, including qualified plans ("Qualified Plans") and nonqualified plans ("Supplemental Plans"). The Qualified Plans provide retirement benefits for U.S. and Canadian employees meeting certain age and service requirements. Benefits for the Qualified Plans are based on the employee's years of service and compensation and are funded from assets held in the plans' trusts.

Devon has a funding policy regarding the Qualified Plans such that it will contribute the amount of funds necessary so that the Qualified Plans' assets will be approximately equal to the related accumulated benefit obligation. As of December 31, 2006 and 2005, the fair value of the Qualified Plans' assets were $590 million and $533 million, respectively, which was $59 million and $37 million more, respectively, than the related accumulated benefit obligation. The actual amount of contributions required during future periods will depend on investment returns from the plan assets during the same period as well as changes in long-term interest rates.

The Supplemental Plans provide retirement benefits for certain employees whose benefits under the Qualified Plans are limited by income tax regulations. The Supplemental Plans' benefits are based on the employee's years of service and compensation. For certain Supplemental Plans, Devon has established trusts to fund these plans' benefit obligations. The total value of these trusts was $59 million at both December 31, 2006 and 2005, and is included in non-current other assets in the consolidated balance sheets. For the remaining Supplemental Plans for which trusts have not been established, benefits are funded from Devon's available cash and cash equivalents.

Devon also has defined benefit postretirement plans ("Postretirement Plans") which provide benefits for substantially all U.S. employees. The Postretirement Plans provide medical and, in some cases, life insurance benefits and are, depending on the type of plan, either contributory or non-contributory. Benefit obligations for the Postretirement Plans are estimated based on future cost-sharing changes that are consistent with Devon's expressed intent to increase, where possible, contributions from future retirees. Devon's funding policy for the Postretirement Plans is to fund the benefits as they become payable with available cash and cash equivalents.

Devon uses a November 30 measurement date to value its pension and other postretirement benefits obligations. As described in Note 1, Devon will be required to use a December 31 measurement date beginning with the fiscal year ending December 31, 2008. Devon does not expect the change in its measurement date from November 30 to December 31 will have a material effect on the net periodic benefit cost or benefit obligation.

Benefit Obligations and Plan Assets

Beginning with Devon's December 31, 2006 balance sheet, Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106, and 132(R)* requires Devon to recognize on its consolidated balance sheet the funded status of its defined benefit plans. The funded status is measured as the difference between the projected benefit obligation and the fair value of plan assets. The following table presents the incremental effect on Devon's December 31, 2006 balance sheet as a result of adopting this recognition requirement from Statement No. 158.

	BEFORE ADJUSTMENT	ADOPTION ADJUSTMENT	AFTER ADJUSTMENT
		(IN MILLIONS)	
Other noncurrent assets	$ 448	(126)	322
Total assets	$ 35,189	(126)	35,063
Other current liabilities	$ 326	12	338
Other noncurrent liabilities	$ 517	81	598
Deferred income taxes	$ 5,729	(79)	5,650
Accumulated other comprehensive income	$ 1,584	(140)	1,444
Total stockholders' equity	$ 17,582	(140)	17,442
Total liabilities and stockholders' equity	$ 35,189	(126)	35,063

The following table presents the status of Devon's pension and other postretirement benefit plans for 2006 and 2005. The benefit obligation for pension plans represents the projected benefit obligation, while the benefit obligation for the postretirement benefit plans represents the accumulated benefit obligation. The accumulated benefit obligation differs from the projected benefit obligation in that the former includes no assumption about future compensation levels. The accumulated benefit obligation for pension plans at December 31, 2006 and 2005 was $652 million and $607 million, respectively.

		PENSION BENEFITS		OTHER POSTRETIREMENT BENEFITS	
		2006	2005	2006	2005
		(IN MILLIONS)			
CHANGE IN BENEFIT OBLIGATION:					
Benefit obligation at beginning of year	$	666	588	54	50
Service cost		23	18	1	1
Interest cost		39	35	3	3
Participant contributions		—	—	2	2
Amendments		2	—	1	—
Foreign exchange rate changes		1	1	—	—
Actuarial loss		66	50	—	6
Benefits paid		(29)	(26)	(9)	(8)
Benefit obligation at end of year		768	666	52	54
CHANGE IN PLAN ASSETS:					
Fair value of plan assets at beginning of year		533	456	—	—
Actual return on plan assets		79	37	—	—
Employer contributions		6	65	6	6
Participant contributions		—	—	2	2
Benefits paid		(29)	(26)	(8)	(8)
Foreign exchange rate changes		1	1	—	—
Fair value of plan assets at end of year		590	533	—	—
Funded status at end of year		(178)	(133)	(52)	(54)
Unrecognized net actuarial loss		—	195	—	7
Unrecognized prior service cost (benefit)		—	6	—	(8)
Net amount recognized in balance sheet	$	(178)	68	(52)	(55)
AMOUNTS RECOGNIZED IN BALANCE SHEET:					
Noncurrent assets	$	2	—	—	—
Current liabilities		(7)	—	(5)	—
Noncurrent liabilities		(173)	—	(47)	—
Prepaid cost		—	144	—	—
Accrued benefit cost		—	(109)	—	(55)
Intangible asset		—	3	—	—
Additional minimum pension liability		—	30	—	—
Net amount	$	(178)	68	(52)	(55)
AMOUNTS RECOGNIZED IN ACCUMULATED OTHER COMPREHENSIVE INCOME:					
Net actuarial loss	$	214	—	6	—
Prior service cost (benefit)		6	—	(7)	—
Total	$	220	—	(1)	—

The plan assets for pension benefits in the table above exclude the assets held in trusts for the Supplemental Plans. However, employer contributions for pension benefits in the table above include $6 million and $5 million in 2006 and 2005, respectively, which were transferred from the trusts established for the Supplemental Plans.

Certain of Devon's pension and postretirement plans have a projected benefit obligation in excess of plan assets at December 31, 2006 and 2005. The aggregate benefit obligation and fair value of plan assets for these plans is included below.

	DECEMBER 31, 2006	DECEMBER 31, 2005
	(IN MILLIONS)	
Projected benefit obligation	$ 755	707
Fair value of plan assets	$ 574	518

Certain of Devon's pension plans have an accumulated benefit obligation in excess of plan assets at December 31, 2006 and 2005. The aggregate accumulated benefit obligation and fair value of plan assets for these plans is included below.

	DECEMBER 31, 2006	DECEMBER 31, 2005
	(IN MILLIONS)	
Accumulated benefit obligation	$ 121	111
Fair value of plan assets	$ —	—

The plan assets included in the above two tables exclude the Supplemental Plan trusts which had a total value of $59 million at both December 31, 2006 and 2005.

Net Periodic Benefit Cost and Other Comprehensive Income

The following table presents the components of net periodic benefit cost and other comprehensive income for Devon's pension and other postretirement benefit plans for 2006, 2005 and 2004.

	PENSION BENEFITS			OTHER POSTRETIREMENT BENEFITS		
	2006	2005	2004	2006	2005	2004
	(IN MILLIONS)					
NET PERIODIC BENEFIT COST:						
Service cost	$ 23	18	15	1	1	1
Interest cost	39	35	32	3	3	4
Expected return on plan assets	(44)	(36)	(30)	—	—	—
Termination benefits	—	—	1	—	—	—
Amortization of prior service cost	1	1	1	—	(1)	(1)
Recognition of net actuarial loss	12	8	7	1	—	—
Net periodic benefit cost	$ 31	26	26	5	3	4
OTHER COMPREHENSIVE INCOME:						
Change in additional minimum pension liability	$ 30	(8)	61	—	—	—

The following table presents the estimated net actuarial loss and prior service cost for the pension and other postretirement plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost during 2007.

	PENSION BENEFITS	OTHER POSTRETIREMENT BENEFITS
	(IN MILLIONS)	
Net actuarial loss	$ 15	1
Prior service cost	1	—
Total	$ 16	1

Assumptions

The following table presents the weighted average actuarial assumptions that were used to determine benefit obligations and net periodic benefit costs for 2006, 2005 and 2004.

	PENSION BENEFITS			OTHER POSTRETIREMENT BENEFITS		
	2006	2005	2004	2006	2005	2004
			(IN MILLIONS)			
ASSUMPTIONS TO DETERMINE BENEFIT OBLIGATIONS:						
Discount rate	5.72%	5.72%	5.74%	5.50%	5.75%	5.75%
Rate of compensation increase	7.00%	4.50%	4.50%	N/A	N/A	N/A
ASSUMPTIONS TO DETERMINE NET PERIODIC BENEFIT COST:						
Discount rate	5.72%	5.98%	6.23%	5.75%	6.00%	6.25%
Expected return on plan assets	8.40%	8.40%	8.34%	N/A	N/A	N/A
Rate of compensation increase	4.50%	4.50%	4.88%	N/A	N/A	N/A

Discount rate Future pension and postretirement obligations are discounted at the end of each year based on the rate at which obligations could be effectively settled, considering the timing of estimated benefit payments. This rate is based on high-quality bond yields, after allowing for call and default risk. High quality corporate bond yield indices, such as Moody's Aa, are considered when selecting the discount rate.

Rate of compensation increase For measurement of the 2006 benefit obligation for the pension plans, the 7% compensation increase in the table above represents the assumed increase for 2007 and 2008. The rate was assumed to decrease one percent annually to 5% in the year 2010 and remain at that level thereafter. For measurement of the 2005 and 2004 benefit obligations for the pension plans, the compensation increases in the table above represent the assumed increases for all future years.

Expected return on plan assets Devon's overall investment objective for its retirement plans' assets is to achieve long-term growth of invested capital to ensure payments of retirement benefits obligations can be funded when required. To assist in achieving this objective, Devon has established certain investment strategies, including target allocation percentages and permitted and prohibited investments, designed to mitigate risks inherent with investing. At December 31, 2006, the target investment allocation for Devon's plan assets was 50% U.S. large cap equity securities; 15% U.S. small cap equity securities, equally allocated between growth and value; 15% international equity securities, equally allocated between growth and value; and 20% debt securities. Derivatives or other speculative investments considered high-risk are generally prohibited.

The expected rate of return on plan assets was determined by evaluating input from external consultants and economists as well as long-term inflation assumptions. Devon expects the long-term asset allocation to approximate the targeted allocation. Therefore, the expected long-term rate of return on plan assets is based on the target allocation of investment types in such assets.

The following table presents the weighted-average asset allocation for Devon's pension plans at December 31, 2006 and 2005, and the target allocation for 2007 by asset category:

	2007	2006	2005
		(IN MILLIONS)	
ASSET CATEGORY:			
Equity securities	80%	83%	83%
Debt securities	20%	17%	16%
Other	—	—	1%
Total	100%	100%	100%

Other assumptions For measurement of the benefit obligation for the other postretirement medical plans, a 10% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2007. The rate was assumed to decrease one percent annually to 5% in the year 2012 and remain at that level thereafter. Assumed health care cost-trend rates affect the amounts reported for retiree health care costs. A one-percentage-point change in the assumed health care cost-trend rates would have the following effects on the December 31, 2006 other postretirement benefits obligation and the 2006 service and interest cost components of net periodic benefit cost.

	ONE PERCENT INCREASE	ONE PERCENT DECREASE
	(IN MILLIONS)	
Effect on benefit obligation	$ 1	(1)
Effect on service and interest costs	$ —	—

Expected Cash Flows

The following table presents expected cash flow information for Devon's pension and other postretirement benefit plans.

	PENSION BENEFITS	OTHER POSTRETIREMENT BENEFITS
	(IN MILLIONS)	
Devon contributions – 2007	$ 7	5
Benefit payments:		
2007	$ 30	5
2008	$ 31	5
2009	$ 33	5
2010	$ 35	5
2011	$ 37	5
2012-2016	$ 245	21

Expected contributions included in the table above include amounts related to Devon's Qualified Plans, Supplemental Plans and Postretirement Plans. Of the benefits expected to be paid in 2007, $7 million of pension benefits is expected to be funded from the trusts established for the Supplemental Plans and all $5 million of other postretirement benefits is expected to be funded from Devon's available cash and cash equivalents. Expected employer contributions and benefit payments for other postretirement benefits are presented net of employee contributions.

Other Benefit Plans

Devon has a 401(k) Incentive Savings Plan which covers all domestic employees. At its discretion, Devon may match a certain percentage of the employees' contributions to the plan. The matching percentage is determined annually by the Board of Directors. Devon's matching contributions to the plan were $15 million, $12 million and $11 million for the years ended December 31, 2006, 2005 and 2004, respectively.

Devon has defined contribution pension plans for its Canadian employees. Devon makes a contribution to each employee which is based upon the employee's base compensation and classification. Such contributions are subject to maximum amounts allowed under the Income Tax Act (Canada). Devon also has a savings plan for its Canadian employees. Under the savings plan, Devon contributes a base percentage amount to all employees and the employee may elect to contribute an additional percentage amount (up to a maximum amount) which is matched by additional Devon contributions. During 2006, 2005 and 2004, Devon's combined contributions to the Canadian defined contribution plan and the Canadian savings plan were $12 million, $10 million and $9 million, respectively.

7. STOCKHOLDERS' EQUITY

The authorized capital stock of Devon consists of 800 million shares of common stock, par value $0.10 per share, and 4.5 million shares of preferred stock, par value $1.00 per share. The preferred stock may be issued in one or more series, and the terms and rights of such stock will be determined by the Board of Directors.

Effective August 17, 1999, Devon issued 1.5 million shares of 6.49% cumulative preferred stock, Series A, to holders of PennzEnergy 6.49% cumulative preferred stock, Series A. Dividends on the preferred stock are cumulative from the date of original issue and are payable quarterly, in cash, when declared by the Board of Directors. The preferred stock is redeemable at the option of Devon at any time on or after June 2, 2008, in whole or in part, at a redemption price of $100 per share, plus accrued and unpaid dividends to the redemption date.

Devon's Board of Directors has designated a certain number of shares of the preferred stock as Series A Junior Participating Preferred Stock (the "Series A Junior Preferred Stock") in connection with the adoption of the shareholder rights plan described later in this note. On April 25, 2003, the Board increased the designated shares from 2.0 million to 2.9 million. At December 31, 2006, there were no shares of Series A Junior Preferred Stock issued or outstanding. The Series A Junior Preferred Stock is entitled to receive cumulative quarterly dividends per share equal to the greater of $1.00 or 200 times the aggregate per share amount of all dividends (other than stock dividends) declared on common stock since the immediately preceding quarterly dividend payment date or, with respect to the first payment date, since the first issuance of Series A Junior Preferred Stock. Holders of the Series A Junior Preferred Stock are entitled to 200 votes per share (subject to adjustment to prevent dilution) on all matters submitted to a vote of the stockholders. The Series A Junior Preferred Stock is neither redeemable nor convertible. The Series A Junior Preferred Stock ranks prior to the common stock but junior to all other classes of Preferred Stock.

At December 31, 2003, a subsidiary of Devon created in the Ocean merger had 38,000 shares of convertible preferred stock outstanding. In January 2004, these shares of convertible preferred stock were canceled and converted to 2,197,160 shares of Devon common stock pursuant to an automatic conversion feature of the preferred stock. The automatic conversion feature was triggered when the closing price of Devon common stock equaled or exceeded the forced conversion price of $26.20 for 20 consecutive trading days.

Stock Repurchases

On September 27, 2004, Devon announced a stock repurchase program to repurchase up to 50 million shares of its common stock. During 2004, Devon repurchased five million shares at a total cost of $189 million, or $37.78 per share. This program was completed in 2005, during which Devon repurchased 44.6 million shares at a total cost of $2.1 billion, or $47.69 per share. The total cost of this program was $2.3 billion, or $46.69 per share.

On August 3, 2005, Devon announced another program to repurchase up to 50 million shares of its common stock. During 2005, Devon repurchased 2.2 million shares at a cost of $134 million, or $60.16 per share, under this program. During 2006, Devon repurchased 4.3 million shares at a cost of $253 million, or $59.61 per share, under this program. As of February 1, 2007, Devon has repurchased 6.5 million shares under this program for $387 million, or $59.80 per share. This program was suspended in 2006 as a result of the Chief acquisition (see Note 3). In conjunction with the sales of Egypt and West Africa (see Note 13), Devon expects to resume this repurchase program in late 2007 by using a portion of the sale proceeds to repurchase common stock. Although this program expires at the end of 2007, it could be extended if necessary.

Shareholder Rights Plan

Under Devon's shareholder rights plan, stockholders have one half of one right for each share of common stock held. The rights become exercisable and separately transferable ten business days after (a) an announcement that a person has acquired, or obtained the right to acquire, 15% or more of the voting shares outstanding, or (b) commencement of a tender or exchange offer that could result in a person owning 15% or more of the voting shares outstanding.

Each right entitles its holder (except a holder who is the acquiring person) to purchase either (a) 1/100 of a share of Series A Preferred Stock for $185.00, subject to adjustment or, (b) Devon common stock with a value equal to twice the exercise price of the right, subject to adjustment to prevent dilution. In the event of certain merger or asset sale transactions with another party or transactions which would increase the equity ownership of a shareholder who then owned 15% or more of Devon, each Devon right will entitle its holder to purchase securities of the merging or acquiring party with a value equal to twice the exercise price of the right.

The rights, which have no voting power, expire on August 17, 2009. The rights may be redeemed by Devon for $0.01 per right until the rights become exercisable.

Dividends

Dividends on Devon's common stock were paid in 2006, 2005 and 2004 at a per share rate of $0.1125, $0.075 and $0.05 per quarter, respectively.

8. COMMITMENTS AND CONTINGENCIES

Devon is party to various legal actions arising in the normal course of business. Matters that are probable of unfavorable outcome to Devon and which can be reasonably estimated are accrued. Such accruals are based on information known about the matters, Devon's estimates of the outcomes of such matters and its experience in contesting, litigating and settling similar matters. None of the actions are believed by management to involve future amounts that would be material to Devon's financial position or results of operations after consideration of recorded accruals although actual amounts could differ materially from management's estimate.

Environmental Matters

Devon is subject to certain laws and regulations relating to environmental remediation activities associated with past operations, such as the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") and similar state statutes. In response to liabilities associated with these activities, accruals have been established when reasonable estimates are possible. Such accruals primarily include estimated costs associated with remediation. Devon has not used discounting in determining its accrued liabilities for environmental remediation, and no material claims for possible recovery from third party insurers or other parties related to environmental costs have been recognized in Devon's consolidated financial statements. Devon adjusts the accruals when new remediation responsibilities are discovered and probable costs become estimable, or when current remediation estimates must be adjusted to reflect new information.

Certain of Devon's subsidiaries acquired in past mergers are involved in matters in which it has been alleged that such subsidiaries are potentially responsible parties ("PRPs") under CERCLA or similar state legislation with respect to various waste disposal areas owned or operated by third parties. As of December 31, 2006, Devon's consolidated balance sheet included $5 million of non-current accrued liabilities, reflected in "Other liabilities," related to these and other environmental remediation liabilities. Devon does not currently believe there is a reasonable possibility of incurring additional material costs in excess of the current accruals recognized for such environmental remediation activities. With respect to the sites in which Devon subsidiaries are PRPs, Devon's conclusion is based in large part on (i) Devon's participation in consent decrees with both other PRPs and the Environmental Protection Agency, which provide for performing the scope of work required for remediation and contain covenants not to sue as protection to the PRPs, (ii) participation in groups as a *de minimis* PRP, and (iii) the availability of other defenses to liability. As a result, Devon's monetary exposure is not expected to be material.

Royalty Matters

Numerous gas producers and related parties, including Devon, have been named in various lawsuits alleging violation of the federal False Claims Act. The suits allege that the producers and related parties used below-market prices, improper deductions, improper measurement techniques and transactions with affiliates which resulted in underpayment of royalties in connection with natural gas and natural gas liquids produced and sold from federal and Indian owned or controlled lands. The principal suit in which Devon is a defendant is United States ex rel. Wright v. Chevron USA, Inc. et al. (the "Wright case"). The suit was originally filed in August 1996 in the United States District Court for the Eastern District of Texas, but was consolidated in October 2000 with the other suits for pre-trial proceedings in the United States District Court for the District of Wyoming. On July 10, 2003, the District of Wyoming remanded the Wright case back to the Eastern District of Texas to resume proceedings. Trial is set for November 2007. Devon believes that it has acted reasonably, has legitimate and strong defenses to all allegations in the suit, and has paid royalties in good faith. Devon does not currently believe that it is subject to material exposure in association with this lawsuit and no liability has been recorded in connection therewith.

In 1995, the United States Congress passed the Deep Water Royalty Relief Act. The intent of this legislation was to encourage deep water exploration in the Gulf of Mexico by providing relief from the obligation to pay royalties on certain federal leases. Deep water leases issued in certain years by the Minerals Management Service (the "MMS") have contained price thresholds, such that if the market prices for oil or natural gas exceeded the thresholds for a given year, royalty relief would not be granted for that year. Deep water leases issued in 1998 and 1999 did not include price thresholds. The MMS in 2006 informed Devon and other oil and gas companies that the omission of price thresholds from these leases was an error on its part and was not its intention. Accordingly, the MMS invited Devon and the other affected oil and gas producers to renegotiate the terms and conditions of the 1998 and 1999 leases to add price threshold provisions to the lease agreements for periods after October 1, 2006. Devon has since had several discussions with MMS representatives on this issue, but has not yet entered into renegotiated leases.

The U.S. House of Representatives in January 2007 passed legislation that would require companies to renegotiate the 1998 and 1999 leases as a condition of securing future federal leases. If this legislation were to become law, it would require price thresholds to be effective in the renegotiated 1998 and 1999 leases effective October 1, 2006. Although Devon has not yet signed renegotiated leases, it has accrued in its 2006 consolidated financial statements approximately $6 million for royalties that would be due if price thresholds were added to its 1998 and 1999 leases effective October 1, 2006.

Equatorial Guinea Investigation

The SEC has been conducting an inquiry into payments made to the government of Equatorial Guinea and to officials and persons affiliated with officials of the government of Equatorial Guinea. On August 9, 2005, Devon received a subpoena issued by the SEC pursuant to a formal order of investigation. Devon has cooperated fully with the SEC's requests for information in this inquiry. After responding in 2005 to such requests for information, Devon has not been contacted by the SEC. In the event that Devon receives any further inquiries, Devon will work with the SEC in connection with its investigation.

Hurricane Contingencies

Historically, Devon maintained a comprehensive insurance program that included coverage for physical damage to its offshore facilities caused by hurricanes. Devon's historical insurance program also included substantial business interruption coverage which Devon is utilizing to recover costs associated with the suspended production related to hurricanes that struck the Gulf of Mexico in the third quarter of 2005. Under the terms of this insurance program, Devon was entitled to be reimbursed for the portion of production suspended longer than forty-five days, subject to upper limits to oil and natural gas prices. Also, the terms of the insurance include a standard, per-event deductible of $1 million for offshore losses as well as a $15 million aggregate annual deductible.

Based on current estimates of physical damage and the anticipated length of time Devon will have production suspended, Devon expects its policy recoveries will exceed repair costs and deductible amounts. This expectation is based upon several variables, including the $467 million received in the third quarter of 2006 as a full settlement of the amount due from Devon's primary insurers. As of December 31, 2006, $154 million of these proceeds had been utilized as reimbursement of past repair costs and deductible amounts. The remaining proceeds of $313 million will be utilized as reimbursement of Devon's anticipated future repair costs. Devon has not yet received any settlements related to claims filed with its secondary insurers.

Should Devon's total policy recoveries, including the partial settlements already received from Devon's primary insurers, exceed all repair costs and deductible amounts, such excess will be recognized as other income in the statement of operations in the period in which such determination can be made.

The policy underlying the insurance program terms described above expired on August 31, 2006. During the third quarter of 2006, Devon was able to re-establish a comprehensive insurance program that includes business interruption and physical damage coverage for its business. However, due to significant changes in the marketplace, Devon was only able to obtain a de minimis amount of coverage for any damage that may be caused by named windstorms in the Gulf of Mexico. Devon has not experienced any losses under this new insurance arrangement through December 31, 2006.

Other Matters

Devon is involved in other various routine legal proceedings incidental to its business. However, to Devon's knowledge as of the date of this report, there were no other material pending legal proceedings to which Devon is a party or to which any of its property is subject.

Commitments

Devon has certain drilling and facility obligations under contractual agreements with third party service providers to procure drilling rigs and other related services for developmental and exploratory drilling and facilities construction. Included in the $3.0 billion total of "Drilling and Facility Obligations" in the table below is $1.9 billion which relates to long-term contracts for three deepwater drilling rigs and certain other contracts for onshore drilling and facility obligations in which drilling or facilities construction has not commenced. The $1.9 billion represents the gross commitment under these contracts. Devon's ultimate payment for these commitments will be reduced by the amounts billed to its partners when net working interests are ultimately determined. Payments for these commitments, net of amounts billed to partners, will be capitalized as a component of oil and gas properties.

Devon has certain firm transportation agreements which represent "ship or pay" arrangements whereby Devon has committed to ship certain volumes of oil, gas and NGLs for a fixed transportation fee. Devon has entered into these agreements to aid the movement of its production to market. Devon expects to have sufficient production to utilize the majority of these transportation services.

Devon leases certain office space and equipment under operating lease arrangements. Total rental expense included in general and administrative expenses under operating leases, net of sub-lease income, was $36 million, $35 million and $49 million in 2006, 2005 and 2004, respectively.

Devon assumed two offshore platform spar leases through the 2003 Ocean merger. The spars are being used in the development of the Nansen and Boomvang fields in the Gulf of Mexico. The Boomvang field was divested as part of the 2005 property divestiture program. The Nansen operating lease is for a 20-year term and contains various options whereby Devon may purchase the lessors' interests in the spar. Total rental expense included in lease operating expenses under both the Nansen and Boomvang operating leases was $12 million, $14 million and $17 million in 2006, 2005 and 2004, respectively. Devon has guaranteed that the Nansen spar will have a residual value at the end of the operating lease equal to at least 10% of the fair value of the spar at the inception of the lease. The total guaranteed value is $14 million in 2022. However, such amount may be reduced under the terms of the lease agreement. As a result of the sale of the Boomvang field, Devon is subleasing the Boomvang Spar. If the sublessee were to default on its obligation, Devon would continue to be obligated to pay the periodic lease payments and any guaranteed value required at the end of the term.

Devon has a floating, production, storage and offloading facility ("FPSO") that is being used in the Panyu project offshore China and is being leased under operating lease arrangements. This lease expires in September 2009. Devon was also leasing an FPSO that is being used in the Zafiro field offshore Equatorial Guinea. Devon and the other working interest owners purchased this FPSO in the fourth quarter of 2005. Total rental expense included in lease operating expenses under both the China and Equatorial Guinea operating leases was $9 million, $19 million and $20 million in 2006, 2005 and 2004, respectively.

The following is a schedule by year of future minimum payments for drilling and facility obligations, firm transportation agreements and leases that have initial or remaining noncancelable lease terms in excess of one year as of December 31, 2006:

YEAR ENDING DECEMBER 31,	DRILLING AND FACILITY OBLIGATIONS	FIRM TRANSPORTATION AGREEMENTS	OFFICE AND EQUIPMENT LEASES	SPAR LEASES	FPSO LEASES
			(IN MILLIONS)		
2007	$ 886	123	48	11	21
2008	524	92	44	11	31
2009	613	81	37	11	29
2010	480	61	29	11	23
2011	364	45	26	11	23
Thereafter	126	172	31	141	57
Total payments	$ 2,993	574	215	196	184

9. SHARE-BASED COMPENSATION

On June 8, 2005, Devon's stockholders adopted the 2005 Long-Term Incentive Plan which expires on June 8, 2013. Devon's stockholders adopted certain amendments to this plan on June 7, 2006. This plan, as amended, authorizes the Compensation Committee, which consists of non-management members of Devon's Board of Directors, to grant nonqualified and incentive stock options, restricted stock awards, Canadian restricted stock units, performance units, performance bonuses, stock appreciation rights and cash-out rights to eligible employees. The plan also authorizes the grant of nonqualified stock options, restricted stock awards and stock appreciation rights to directors. A total of 32 million shares of Devon common stock have been reserved for issuance pursuant to the plan. To calculate shares issued under the plan, options granted represent one share and other awards represent 2.2 shares.

Devon also has stock option plans that were adopted in 2003 and 1997 under which stock options and restricted stock awards were issued to key management and professional employees. Options granted under these plans remain exercisable by the employees owning such options, but no new options or restricted stock awards will be granted under these plans. Devon also has stock options outstanding that were assumed as part of the acquisitions of Ocean, Mitchell Energy & Development Corp., Santa Fe Snyder and PennzEnergy.

As discussed in Note 1, on January 1, 2006, Devon changed its method of accounting for share-based compensation from the APB No. 25 intrinsic value accounting method to the fair value recognition provisions of SFAS No. 123(R). The following table presents the effects of share-based compensation included in Devon's accompanying statement of operations for the years ended December 31, 2006, 2005 and 2004.

	2006	2005	2004
		(IN MILLIONS)	
Gross general and administrative expense	$ 91	29	12
Share-based compensation expense capitalized pursuant to the full cost method of accounting for oil and gas properties	$ 26	—	—
Related income tax benefit	$ 23	11	5

Stock Options

Under Devon's 2005 Long-Term Incentive Plan, the exercise price of stock options granted may not be less than the estimated fair market value of the stock at the date of grant. In addition, options granted are exercisable during a period established for each grant, which period may not exceed eight years from the date of grant. The recipient must pay the exercise price in cash or in common stock, or a combination thereof, at the time that the option is exercised. Options granted generally have a vesting period that ranges from three to four years.

The fair value of stock options on the date of grant is expensed over the applicable vesting period. Devon estimates the fair values of stock options granted using a Black-Scholes option valuation model, which requires Devon to make several assumptions. The volatility of Devon's common stock is based on the historical volatility of the market price of Devon's common stock over a period of time equal to the expected term of the option and ending on the grant date. The dividend yield is based on Devon's historical and current yield in effect at the date of grant. The risk-free interest rate is based on the zero-coupon U.S. Treasury yield for the expected term of the option at the date of grant. The expected term of the options is based on historical exercise and termination experience for various groups of employees and directors. Each group is determined based on the similarity of their historical exercise and termination behavior.

The following table presents a summary of the grant-date fair values of stock options granted and the related assumptions for the years ended December 31, 2006, 2005 and 2004. All such amounts represent the weighted-average amounts for each year.

	2006	2005	2004
		(IN MILLIONS)	
Grant-date fair value	$ 22.41	19.65	10.32
Volatility factor	32.2%	31.0%	32.2%
Dividend yield	0.5%	0.6%	0.5%
Risk-free interest rate	5.7%	4.4%	3.2%
Expected term (in years)	4.0	4.2	4.0

The following table presents a summary of Devon's outstanding stock options as of December 31, 2006, including changes during the year then ended.

	OPTIONS	WEIGHTED AVERAGE EXERCISE PRICE	WEIGHTED AVERAGE REMAINING CONTRACTUAL TERM	AGGREGATE INTRINSIC VALUE
	(IN THOUSANDS)		(IN YEARS)	(IN MILLIONS)
Outstanding at December 31, 2005	16,732	$ 32.74		
Granted	1,874	$ 70.00		
Exercised	(2,846)	$ 25.41		
Forfeited	(377)	$ 49.16		
Outstanding at December 31, 2006	15,383	$ 38.24	4.1	$ 450
Vested and expected to vest at December 31, 2006	14,952	$ 37.51	4.1	$ 448
Exercisable at December 31, 2006	11,034	$ 29.44	3.8	$ 416

The aggregate intrinsic value of stock options that were exercised during 2006, 2005 and 2004 was $119 million, $149 million and $168 million, respectively. As of December 31, 2006, Devon's unrecognized compensation cost related to unvested stock options was $77 million. Such cost is expected to be recognized over a weighted-average period of 2.4 years.

Restricted Stock Awards and Units

Under Devon's 2005 Long-Term Incentive Plan, restricted stock awards and units are subject to the terms, conditions, restrictions and/or limitations, if any, that the Compensation Committee deems appropriate, including restrictions on continued employment. Generally, restricted stock awards and units vest over a minimum restriction period of at least three years from the date of grant. During the vesting period, recipients of restricted stock awards receive dividends which are not subject to restrictions or other limitations. The fair value of restricted stock awards and units on the date of grant is expensed over the applicable vesting period. Devon estimates the fair values of restricted stock awards and units as the closing price of Devon's common stock on the grant date of the award or unit.

The following table presents a summary of Devon's unvested restricted stock awards as of December 31, 2006, including changes during the year then ended.

	RESTRICTED STOCK AWARDS	WEIGHTED AVERAGE GRANT-DATE FAIR VALUE
	(IN THOUSANDS)	
Unvested at December 31, 2005	3,417	$ 46.80
Granted	3,091	$ 65.68
Vested	(1,156)	$ 42.58
Forfeited	(190)	$ 47.54
Unvested at December 31, 2006	5,162	$ 58.35

The aggregate fair value of restricted stock awards that vested during 2006, 2005 and 2004 was $82 million, $51 million and $15 million, respectively. As of December 31, 2006, Devon's unrecognized compensation cost related to unvested restricted stock awards and units was $253 million. Such cost is expected to be recognized over a weighted-average period of 2.9 years.

10. REDUCTION OF CARRYING VALUE OF OIL AND GAS PROPERTIES

During 2006 and 2005, Devon reduced the carrying value of certain of its oil and gas properties due to full cost ceiling limitations and unsuccessful exploratory activities. A summary of these reductions and additional discussion is provided below.

	YEAR ENDED DECEMBER 31,			
	2006		2005	
	GROSS	NET OF TAXES	GROSS	NET OF TAXES
	(IN MILLIONS)			
Unsuccessful exploratory reductions:				
Nigeria	$ 85	85	—	—
Brazil	16	16	42	42
Angola	—	—	170	119
Ceiling test reduction - Russia	20	10	—	—
Total	$ 121	111	212	161

2006 Reductions Devon has committed to drill four wells in Nigeria. The first two wells were unsuccessful. After drilling the second unsuccessful well in the first quarter of 2006, Devon determined that the capitalized costs related to these two wells should be impaired. Therefore, in the first quarter of 2006, Devon recognized an $85 million impairment of its investment in Nigeria equal to the costs to drill the two dry holes and a proportionate share of block-related costs. There was no tax benefit related to this impairment.

During the second quarter of 2006, Devon drilled two unsuccessful exploratory wells in Brazil and determined that the capitalized costs related to these two wells should be impaired. Therefore, in the second quarter of 2006, Devon recognized a $16 million impairment of its investment in Brazil equal to the costs to drill the two dry holes and a proportionate share of block-related costs. There was no tax benefit related to this impairment. The two wells were unrelated to Devon's Polvo development project in Brazil.

As a result of a decline in projected future net cash flows, the carrying value of Devon's Russian properties exceeded the full cost ceiling by $10 million at the end of the third quarter of 2006. Therefore, Devon recognized a $20 million reduction of the carrying value of its oil and gas properties in Russia, offset by a $10 million deferred income tax benefit.

2005 Reductions Devon's interests in Angola were acquired through the 2003 Ocean Energy merger. Devon's Angolan drilling program discovered no proven reserves. After drilling three unsuccessful wells in the fourth quarter of 2005, Devon determined that all of the Angolan capitalized costs should be impaired.

Prior to the fourth quarter of 2005, Devon was capitalizing the costs of previous unsuccessful efforts in Brazil pending the determination of whether proved reserves would be recorded in Brazil. Devon has been successful in its drilling efforts on block BM-C-8 in Brazil and is currently developing the Polvo project on this block. The ultimate value of the Polvo project is expected to be in excess of the sum of its related costs, plus the costs of the previous unrelated unsuccessful efforts in Brazil which were capitalized. However, the Polvo proved reserves will be recorded over a period of time. At the end of 2005, it was expected that a small initial portion of the proved reserves ultimately expected at Polvo would be recorded in 2006. Based on preliminary estimates developed in the fourth quarter of 2005, the value of this initial partial booking of proved reserves was not sufficient to offset the sum of the related proportionate Polvo costs plus the costs of the previous unrelated unsuccessful efforts. Therefore, Devon determined that the prior unsuccessful costs unrelated to the Polvo project should be impaired. These costs totaled approximately $42 million. There was no tax benefit related to this Brazilian impairment.

11. OTHER INCOME

The components of other income include the following:

	YEAR ENDED DECEMBER 31,		
	2006	2005	2004
		(IN MILLIONS)	
Interest and dividend income	$ 100	95	45
Net gain on sales of non-oil and gas property and equipment	6	150	33
Loss on derivative financial instruments	—	(48)	—
Gains from changes in foreign exchange rates	—	2	23
Other	9	(1)	25
Total	$ 115	198	126

12. INCOME TAXES

At December 31, 2006, Devon had the following net operating loss carryforwards which are available to reduce future taxable income in the jurisdiction where the net operating loss was incurred. These carryforwards will result in a future tax reduction based upon the future tax rate applicable to the taxable income that is ultimately offset by the net operating loss carryforward. For financial purposes, the tax effects of these carryforwards have been recognized as reductions to the net deferred tax liability at December 31, 2006.

JURISDICTION	YEARS OF EXPIRATION	CARRYFORWARD AMOUNTS
		(IN MILLIONS)
Various U.S. states	2007 – 2022	$ 110
Canada	2008 – 2027	$ 143
Brazil	Indefinite	$ 31

The earnings from continuing operations before income taxes and the components of income tax expense (benefit) for the years 2006, 2005 and 2004 were as follows:

	YEAR ENDED DECEMBER 31, 2006	2005	2004
		(IN MILLIONS)	
EARNINGS FROM CONTINUING OPERATIONS BEFORE INCOME TAXES:			
U.S.	$ 2,435	3,254	2,264
Canada	751	899	598
International	826	352	414
Total	$ 4,012	4,505	3,276
CURRENT INCOME TAX EXPENSE:			
U.S. federal	$ 292	735	346
Various states	7	26	10
Canada	143	106	49
International	377	351	320
Total current tax expense	819	1,218	725
DEFERRED INCOME TAX EXPENSE (BENEFIT):			
U.S. federal	456	271	246
Various states	77	(18)	27
Canada	(105)	217	149
International	(58)	(82)	(52)
Total deferred tax expense	370	388	370
Total income tax expense	$ 1,189	1,606	1,095

The taxes on the results of discontinued operations presented in the accompanying statements of operations were all related to international operations.

Total income tax expense differed from the amounts computed by applying the U.S. federal income tax rate to earnings from continuing operations before income taxes as a result of the following:

	YEAR ENDED DECEMBER 31, 2006	2005	2004
		(IN MILLIONS)	
Expected income tax expense based on U.S. statutory tax rate of 35%	$ 1,404	1,577	1,146
Effect of Canadian tax rate reductions	(243)	(14)	(36)
U.S. manufacturing deduction	(12)	(25)	—
Repatriation of Canadian earnings	—	28	—
State income taxes	55	6	20
Taxation on foreign operations	(22)	30	(35)
Other	7	4	—
Total income tax expense	$ 1,189	1,606	1,095

In 2006, 2005 and 2004, deferred income taxes were reduced $243 million, $14 million and $36 million, respectively, due to Canadian statutory rate reductions that were enacted in each such year.

In 2006 and 2005, income taxes were reduced $12 million and $25 million, respectively, due to a new U.S. tax deduction for companies with domestic production activities, including oil and gas extraction.

In 2006, deferred income taxes increased $39 million due to the effect of a new income-based tax enacted by the state of Texas that replaces a previous franchise tax. The new tax is effective January 1, 2007. The $39 million increase is included in 2006 state income taxes in the above table.

In 2005, Devon recognized $28 million of taxes related to its repatriation of $545 million to the U.S. The cash was repatriated due to tax legislation that allowed qualifying companies to repatriate cash from foreign operations at a reduced income tax rate. Substantially all of the cash repatriated by Devon in 2005 related to earnings of its Canadian subsidiary.

The tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities at December 31, 2006 and 2005 are presented below:

		DECEMBER 31,	
		2006	2005
		(IN MILLIONS)	
DEFERRED TAX ASSETS:			
Net operating loss carryforwards	$	35	148
Minimum tax credit carryforwards		—	18
Fair value of derivative financial instruments		97	52
Asset retirement obligations		270	271
Pension benefit obligations		81	49
Insurance proceeds		113	—
Other		108	102
Total deferred tax assets		704	640
DEFERRED TAX LIABILITIES:			
Property and equipment, principally due to nontaxable business combinations, differences in depreciation, and the expensing of intangible drilling costs for tax purposes		(5,743)	(5,406)
Chevron Corporation common stock		(326)	(247)
Long-term debt		(148)	(168)
Other		(35)	(35)
Total deferred tax liabilities		(6,252)	(5,856)
Net deferred tax liability	$	(5,548)	(5,216)

As shown in the above table, Devon has recognized $704 million of deferred tax assets as of December 31, 2006. Such amount includes $35 million from various carryforwards available to offset future income taxes. The carryforwards include state net operating loss carryforwards which expire primarily between 2007 and 2022, Canadian net operating loss carryforwards which expire primarily between 2008 and 2027, and Brazilian net operating loss carryforwards which have no expiration. The tax benefits of carryforwards are recorded as an asset to the extent that management assesses the utilization of such carryforwards to be "more likely than not." When the future utilization of some portion of the carryforwards is determined not to be "more likely than not," a valuation allowance is provided to reduce the recorded tax benefits from such assets.

Devon expects the tax benefits from the net operating loss carryforwards to be utilized between 2007 and 2010. Such expectation is based upon current estimates of taxable income during this period, considering limitations on the annual utilization of these benefits as set forth by tax regulations. Significant changes in such estimates caused by variables such as future oil and gas prices or capital expenditures could alter the timing of the eventual utilization of such carryforwards. There can be no assurance that Devon will generate any specific level of continuing taxable earnings. However, management believes that Devon's future taxable income will more likely than not be sufficient to utilize substantially all its tax carryforwards prior to their expiration.

13. DISCONTINUED OPERATIONS

Egypt

On November 14, 2006, Devon announced its plans to divest its operations in Egypt. Pursuant to accounting rules for discontinued operations, Devon has classified all 2006 and prior period amounts related to its operations in Egypt as discontinued operations. Devon anticipates completing the sale of its Egyptian assets during the first half of 2007. As of December 31, 2006, Devon has not recorded any gain or loss associated with this planned sale.

Revenues related to Devon's operations in Egypt totaled $118 million, $119 million and $133 million during 2006, 2005 and 2004, respectively. The following table presents the main classes of assets and liabilities associated with Devon's operations in Egypt as of December 31, 2006 and 2005.

	AS OF DECEMBER 31,	
	2006	2005
	(IN MILLIONS)	
ASSETS:		
Cash	$ 17	13
Accounts receivable	32	36
Other current assets	32	17
Current assets	$ 81	66
Long-term assets – property and equipment, net of accumulated depreciation, depletion and amortization	$ 185	217
LIABILITIES:		
Current liabilities – accounts payable – trade	$ 5	19
Asset retirement obligation, long-term	$ 9	8
Deferred income taxes	15	31
Other liabilities	1	1
Long-term liabilities	$ 25	40

West Africa (Subsequent Event)

On January 23, 2007 Devon announced its plans to divest its operations in West Africa. Pursuant to accounting rules for discontinued operations, Devon has not classified the assets, liabilities or operating results of its operations in West Africa as discontinued operations as of December 31, 2006. However, such amounts will be classified as discontinued operations beginning with the first quarter of 2007. Devon anticipates completing the sale of its West African assets during the third quarter of 2007. As of December 31, 2006, Devon has not recorded any gain or loss associated with this planned sale.

The following table presents the main classes of assets and liabilities associated with Devon's operations in West Africa as of December 31, 2006 and 2005.

	AS OF DECEMBER 31,	
	2006	2005
	(IN MILLIONS)	
ASSETS:		
Cash	$ 47	62
Accounts receivable	69	190
Other current assets	35	31
Current assets	$ 151	283
Long-term assets – property and equipment, net of accumulated depreciation, depletion and amortization	$ 1,434	1,515
LIABILITIES:		
Accounts payable – trade	$ 43	64
Income taxes payable	115	101
Current portion of asset retirement obligation	8	—
Accrued expenses and other current liabilities	2	—
Current liabilities	$ 168	165
Asset retirement obligation, long-term	$ 29	24
Deferred income taxes	360	397
Other liabilities	15	15
Long-term liabilities	$ 404	436

14. SEGMENT INFORMATION

Devon manages its business by country. As such, Devon identifies its segments based on geographic areas. Devon has three reportable segments: its operations in the U.S., its operations in Canada, and its international operations outside of North America. Substantially all of these segments' operations involve oil and gas producing activities. Certain information regarding such activities for each segment is included in Note 15.

Following is certain financial information regarding Devon's segments for 2006, 2005 and 2004. The revenues reported are all from external customers.

	U.S.	CANADA	INTERNATIONAL	TOTAL
		(IN MILLIONS)		
AS OF DECEMBER 31, 2006:				
Current assets	$ 1,307	616	1,289	3,212
Property and equipment, net of accumulated depreciation, depletion and amortization	15,253	6,929	2,413	24,595
Goodwill	3,053	2,585	68	5,706
Other assets	1,289	35	226	1,550
Total assets	$ 20,902	10,165	3,996	35,063
Current liabilities	$ 3,693	569	383	4,645
Long-term debt	2,594	2,974	—	5,568
Asset retirement obligation, long-term	387	360	86	833
Other liabilities	864	16	45	925
Deferred income taxes	3,351	1,831	468	5,650
Stockholders' equity	10,013	4,415	3,014	17,442
Total liabilities and stockholders' equity	$ 20,902	10,165	3,996	35,063
YEAR ENDED DECEMBER 31, 2006:				
Revenues:				
Oil sales	$ 1,218	603	1,384	3,205
Gas sales	3,445	1,456	31	4,932
NGL sales	548	201	—	749
Marketing and midstream revenues	1,641	31	20	1,692
Total revenues	6,852	2,291	1,435	10,578
Expenses and other income, net:				
Lease operating expenses	813	543	132	1,488
Production taxes	235	7	99	341
Marketing and midstream operating costs and expenses	1,226	10	8	1,244
Depreciation, depletion and amortization of oil and gas properties	1,311	644	311	2,266
Depreciation and amortization of non-oil and gas properties	154	18	4	176
Accretion of asset retirement obligation	25	21	3	49
General and administrative expenses	316	92	(11)	397
Interest expense	199	222	—	421
Change in fair value of derivative financial instruments	181	(3)	—	178
Reduction of carrying value of oil and gas properties	—	—	121	121
Other income, net	(43)	(14)	(58)	(115)
Total expenses and other income, net	4,417	1,540	609	6,566
Earnings from continuing operations before income tax expense	2,435	751	826	4,012
Income tax expense (benefit):				
Current	299	143	377	819
Deferred	533	(105)	(58)	370
Total income tax expense	832	38	319	1,189
Earnings from continuing operations	1,603	713	507	2,823
Discontinued operations:				
Earnings from discontinued operations before income taxes	—	—	22	22
Income tax benefit	—	—	(1)	(1)
Earnings from discontinued operations	—	—	23	23
Net earnings	1,603	713	530	2,846
Preferred stock dividends	10	—	—	10
Net earnings applicable to common stockholders	$ 1,593	713	530	2,836
Capital expenditures	$ 5,814	1,670	609	8,093

		U.S.	CANADA	INTERNATIONAL	TOTAL
			(IN MILLIONS)		
AS OF DECEMBER 31, 2005:					
Current assets	$	2,042	1,182	982	4,206
Property and equipment, net of accumulated depreciation, depletion and amortization		10,856	5,877	2,178	18,911
Goodwill		3,056	2,581	68	5,705
Other assets		1,213	17	221	1,451
Total assets	$	17,167	9,657	3,449	30,273
Current liabilities	$	1,736	925	273	2,934
Long-term debt		2,986	2,971	—	5,957
Asset retirement obligation, long-term		320	261	29	610
Other liabilities		467	12	57	536
Deferred income taxes		2,864	2,008	502	5,374
Stockholders' equity		8,794	3,480	2,588	14,862
Total liabilities and stockholders' equity	$	17,167	9,657	3,449	30,273
YEAR ENDED DECEMBER 31, 2005:					
Revenues:					
Oil sales	$	1,062	353	944	2,359
Gas sales		3,929	1,814	41	5,784
NGL sales		484	196	7	687
Marketing and midstream revenues		1,780	12	—	1,792
Total revenues		7,255	2,375	992	10,622
Expenses and other income, net:					
Lease operating expenses		710	498	116	1,324
Production taxes		273	6	56	335
Marketing and midstream operating costs and expenses		1,336	6	—	1,342
Depreciation, depletion and amortization of oil and gas properties		1,137	570	274	1,981
Depreciation and amortization of non-oil and gas properties		141	14	5	160
Accretion of asset retirement obligation		25	16	2	43
General and administrative expenses		245	59	(13)	291
Interest expense		224	309	—	533
Change in fair value of derivative financial instruments		86	8	—	94
Reduction of carrying value of oil and gas properties		—	—	212	212
Other income, net		(176)	(10)	(12)	(198)
Total expenses and other income, net		4,001	1,476	640	6,117
Earnings from continuing operations before income tax expense		3,254	899	352	4,505
Income tax expense (benefit):					
Current		761	106	351	1,218
Deferred		253	217	(82)	388
Total income tax expense		1,014	323	269	1,606
Earnings from continuing operations		2,240	576	83	2,899
Discontinued operations:					
Earnings from discontinued operations before income taxes		—	—	46	46
Income tax expense		—	—	15	15
Earnings from discontinued operations		—	—	31	31
Net earnings		2,240	576	114	2,930
Preferred stock dividends		10	—	—	10
Net earnings applicable to common stockholders	$	2,230	576	114	2,920
Capital expenditures	$	2,200	1,707	308	4,215

		U.S.	CANADA	INTERNATIONAL	TOTAL
			(IN MILLIONS)		
YEAR ENDED DECEMBER 31, 2004:					
Revenues:					
Oil sales	$	976	299	824	2,099
Gas sales		3,261	1,437	34	4,732
NGL sales		405	143	6	554
Marketing and midstream revenues		1,688	13	—	1,701
Total revenues		6,330	1,892	864	9,086
Expenses and other income, net:					
Lease operating expenses		714	438	107	1,259
Production taxes		220	5	30	255
Marketing and midstream operating costs and expenses		1,333	6	—	1,339
Depreciation, depletion and amortization of oil and gas properties		1,242	522	313	2,077
Depreciation and amortization of non-oil and gas properties		130	14	4	148
Accretion of asset retirement obligation		27	15	2	44
General and administrative expenses		221	56	—	277
Interest expense		197	278	—	475
Change in fair value of derivative financial instruments		63	(1)	—	62
Other income, net		(81)	(39)	(6)	(126)
Total expenses and other income, net		4,066	1,294	450	5,810
Earnings before income tax expense		2,264	598	414	3,276
Income tax expense (benefit):					
Current		356	49	320	725
Deferred		273	149	(52)	370
Total income tax expense		629	198	268	1,095
Earnings from continuing operations		1,635	400	146	2,181
Discontinued operations:					
Earnings from discontinued operations before income taxes		—	—	17	17
Income tax expense		—	—	12	12
Earnings from discontinued operations		—	—	5	5
Net earnings		1,635	400	151	2,186
Preferred stock dividends		10	—	—	10
Net earnings applicable to common stockholders	$	1,625	400	151	2,176
Capital expenditures	$	1,674	979	279	2,932

15. SUPPLEMENTAL INFORMATION ON OIL AND GAS OPERATIONS (UNAUDITED)

The following supplemental unaudited information regarding the oil and gas activities of Devon is presented pursuant to the disclosure requirements promulgated by the Securities and Exchange Commission and SFAS No. 69, *Disclosures About Oil and Gas Producing Activities.* This supplemental information excludes amounts for all periods presented related to Devon's discontinued operations in Egypt.

Costs Incurred

The following tables reflect the costs incurred in oil and gas property acquisition, exploration, and development activities:

		TOTAL YEAR ENDED DECEMBER 31,		
		2006	2005	2004
			(IN MILLIONS)	
Property acquisition costs:				
Proved properties	$	1,113	54	38
Unproved properties		1,485	347	141
Exploration costs		973	890	714
Development costs		4,151	2,787	1,917
Costs incurred	$	7,722	4,078	2,810

	DOMESTIC YEAR ENDED DECEMBER 31, 2006	2005	2004
	(IN MILLIONS)		
Property acquisition costs:			
Proved properties	$ 1,066	5	27
Unproved properties	1,366	106	75
Exploration costs	547	422	335
Development costs	2,558	1,597	1,163
Costs incurred	$ 5,537	2,130	1,600

	CANADA YEAR ENDED DECEMBER 31, 2006	2005	2004
	(IN MILLIONS)		
Property acquisition costs:			
Proved properties	$ 23	49	11
Unproved properties	70	239	52
Exploration costs	217	361	272
Development costs	1,244	1,020	625
Costs incurred	$ 1,554	1,669	960

	INTERNATIONAL YEAR ENDED DECEMBER 31, 2006	2005	2004
	(IN MILLIONS)		
Property acquisition costs:			
Proved properties	$ 24	—	—
Unproved properties	49	2	14
Exploration costs	209	107	107
Development costs	349	170	129
Costs incurred	$ 631	279	250

Pursuant to the full cost method of accounting, Devon capitalizes certain of its general and administrative expenses which are related to property acquisition, exploration and development activities. Such capitalized expenses, which are included in the costs shown in the preceding tables, were $269 million, $181 million and $166 million in the years 2006, 2005 and 2004, respectively. Also, Devon capitalizes interest costs incurred and attributable to unproved oil and gas properties and major development projects of oil and gas properties. Capitalized interest expenses, which are included in the costs shown in the preceding tables, were $70 million in each of the years 2006, 2005 and 2004.

Results of Operations for Oil and Gas Producing Activities

The following tables include revenues and expenses associated directly with Devon's oil and gas producing activities, including general and administrative expenses directly related to such producing activities. They do not include any allocation of Devon's interest costs or general corporate overhead and, therefore, are not necessarily indicative of the contribution to net earnings of Devon's oil and gas operations. Income tax expense has been calculated by applying statutory income tax rates to oil, gas and NGL sales after deducting costs, including depreciation, depletion and amortization and after giving effect to permanent differences.

	TOTAL YEAR ENDED DECEMBER 31, 2006	2005	2004
	(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and NGL sales	$ 8,886	8,830	7,385
Production and operating expenses	(1,829)	(1,659)	(1,514)
Depreciation, depletion and amortization	(2,266)	(1,981)	(2,077)
Accretion of asset retirement obligation	(49)	(43)	(44)
General and administrative expenses	(162)	(107)	(104)
Reduction of carrying value of oil and gas properties	(121)	(212)	—
Income tax expense	(1,448)	(1,830)	(1,342)
Results of operations	$ 3,011	2,998	2,304
Depreciation, depletion and amortization per Boe	$ 10.59	8.86	8.41

	DOMESTIC		
	YEAR ENDED DECEMBER 31,		
	2006	2005	2004
	(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and NGL sales	$ 5,211	5,475	4,642
Production and operating expenses	(1,048)	(983)	(934)
Depreciation, depletion and amortization	(1,311)	(1,137)	(1,242)
Accretion of asset retirement obligation	(26)	(25)	(27)
General and administrative expenses	(115)	(84)	(75)
Income tax expense	(996)	(1,145)	(807)
Results of operations	$ 1,715	2,101	1,557
Depreciation, depletion and amortization per Boe	$ 9.89	8.35	8.23

	CANADA		
	YEAR ENDED DECEMBER 31,		
	2006	2005	2004
	(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and NGL sales	$ 2,260	2,363	1,879
Production and operating expenses	(550)	(504)	(443)
Depreciation, depletion and amortization	(644)	(570)	(522)
Accretion of asset retirement obligation	(21)	(16)	(15)
General and administrative expenses	(29)	(20)	(16)
Income tax expense	(144)	(426)	(275)
Results of operations	$ 872	827	608
Depreciation, depletion and amortization per Boe	$ 11.17	9.20	8.00

	INTERNATIONAL		
	YEAR ENDED DECEMBER 31,		
	2006	2005	2004
	(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and NGL sales	$ 1,415	992	864
Production and operating expenses	(231)	(172)	(137)
Depreciation, depletion and amortization	(311)	(274)	(313)
Accretion of asset retirement obligation	(2)	(2)	(2)
General and administrative expenses	(18)	(3)	(13)
Reduction of carrying value of oil and gas properties	(121)	(212)	—
Income tax expense	(308)	(259)	(260)
Results of operations	$ 424	70	139
Depreciation, depletion and amortization per Boe	$ 13.03	10.73	10.13

In 2006, 2005 and 2004, the Canadian income tax amounts in the tables above were reduced by $243 million, $14 million and $36 million, respectively, due to statutory rate reductions that were enacted in each such year.

Quantities of Oil and Gas Reserves

Set forth below is a summary of the reserves which were evaluated, either by preparation or audit, by independent petroleum consultants for each of the years ended 2006, 2005 and 2004.

	2006		2005		2004	
	PREPARED	AUDITED	PREPARED	AUDITED	PREPARED	AUDITED
Domestic	7%	81%	9%	79%	16%	61%
Canada	46%	39%	46%	26%	22%	—
International	99%	—	98%	—	98%	—
Total	28%	61%	31%	54%	28%	35%

"Prepared" reserves are those quantities of reserves which were prepared by an independent petroleum consultant. "Audited" reserves are those quantities of revenues which were estimated by Devon employees and audited by an independent petroleum consultant. An audit is an examination of a company's proved oil and gas reserves and net cash flow by an independent petroleum consultant that is conducted for the purpose of expressing an opinion as to whether such estimates, in aggregate, are reasonable and have been estimated and presented in conformity with generally accepted petroleum engineering and evaluation principles.

The domestic reserves were evaluated by the independent petroleum consultants of LaRoche Petroleum Consultants, Ltd. and Ryder Scott Company, L.P. in each of the years presented. The Canadian reserves were evaluated by the independent petroleum consultants of AJM Petroleum Consultants in each of the years presented. The International reserves were evaluated by the independent petroleum consultants of Ryder Scott Company, L.P. in each of the years presented.

Set forth below is a summary of the changes in the net quantities of crude oil, natural gas and natural gas liquids reserves for each of the three years ended December 31, 2006. Additional discussion of the significant proved reserve changes follows the tables below.

	TOTAL			
	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)	TOTAL (MMBOE)
Proved reserves as of December 31, 2003	646	7,316	209	2,074
Revisions due to prices	(82)	39	1	(75)
Revisions other than price	19	29	21	45
Extensions and discoveries	76	988	25	266
Purchase of reserves	1	14	—	3
Production	(74)	(891)	(24)	(247)
Sale of reserves	(1)	(2)	—	(1)
Proved reserves as of December 31, 2004	585	7,493	232	2,065
Revisions due to prices	(14)	78	4	3
Revisions other than price	21	(2)	16	37
Extensions and discoveries	166	1,220	30	400
Purchase of reserves	2	10	—	4
Production	(62)	(827)	(24)	(224)
Sale of reserves	(58)	(676)	(12)	(183)
Proved reserves as of December 31, 2005	640	7,296	246	2,102
Revisions due to prices	(21)	(89)	(7)	(44)
Revisions other than price	5	(106)	5	(6)
Extensions and discoveries	139	1,491	45	433
Purchase of reserves	—	584	9	106
Production	(55)	(815)	(23)	(214)
Sale of reserves	—	(5)	—	(1)
Proved reserves as of December 31, 2006	708	8,356	275	2,376
Proved developed reserves as of:				
December 31, 2003	392	5,980	179	1,568
December 31, 2004	400	6,219	204	1,640
December 31, 2005	355	6,111	216	1,589
December 31, 2006	358	6,518	229	1,674

DOMESTIC	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)	TOTAL (MMBOE)
Proved reserves as of December 31, 2003	212	4,884	161	1,187
Revisions due to prices	5	8	1	8
Revisions other than price	2	62	23	35
Extensions and discoveries	16	578	16	129
Purchase of reserves	—	8	—	1
Production	(31)	(602)	(19)	(151)
Sale of reserves	(1)	(2)	—	(1)
Proved reserves as of December 31, 2004	203	4,936	182	1,208
Revisions due to prices	6	58	3	19
Revisions other than price	2	238	19	61
Extensions and discoveries	16	793	20	169
Purchase of reserves	—	—	—	—
Production	(25)	(555)	(18)	(136)
Sale of reserves	(29)	(306)	(9)	(89)
Proved reserves as of December 31, 2005	173	5,164	197	1,232
Revisions due to prices	—	(110)	(3)	(22)
Revisions other than price	—	(11)	6	5
Extensions and discoveries	16	1,298	43	274
Purchase of reserves	—	580	9	105
Production	(19)	(566)	(19)	(132)
Sale of reserves	—	—	—	—
Proved reserves as of December 31, 2006	170	6,355	233	1,462
Proved developed reserves as of:				
December 31, 2003	171	3,935	136	964
December 31, 2004	168	4,105	161	1,014
December 31, 2005	149	4,343	175	1,049
December 31, 2006	147	4,916	196	1,163

CANADA	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)	TOTAL (MMBOE)
Proved reserves as of December 31, 2003	148	2,297	48	579
Revisions due to prices	(43)	32	—	(38)
Revisions other than price	5	(46)	(2)	(5)
Extensions and discoveries	50	410	9	127
Purchase of reserves	1	6	—	2
Production	(14)	(279)	(5)	(65)
Sale of reserves	—	—	—	—
Proved reserves as of December 31, 2004	147	2,420	50	600
Revisions due to prices	—	22	1	4
Revisions other than price	2	(242)	(3)	(41)
Extensions and discoveries	144	427	10	225
Purchase of reserves	2	10	—	4
Production	(13)	(261)	(6)	(62)
Sale of reserves	(29)	(370)	(3)	(94)
Proved reserves as of December 31, 2005	253	2,006	49	636
Revisions due to prices	(19)	23	(4)	(20)
Revisions other than price	(1)	(84)	(1)	(16)
Extensions and discoveries	109	193	2	145
Purchase of reserves	—	4	—	1
Production	(13)	(241)	(4)	(58)
Sale of reserves	—	(5)	—	(1)
Proved reserves as of December 31, 2006	329	1,896	42	687
Proved developed reserves as of:				
December 31, 2003	123	1,964	43	493
December 31, 2004	123	2,043	43	507
December 31, 2005	103	1,708	41	429
December 31, 2006	112	1,560	33	405

	INTERNATIONAL [1]			
	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)	TOTAL (MMBOE)
Proved reserves as of December 31, 2003	286	135	—	308
Revisions due to prices	(44)	(1)	—	(45)
Revisions other than price	12	13	—	15
Extensions and discoveries	10	—	—	10
Purchase of reserves	—	—	—	—
Production	(29)	(10)	—	(31)
Sale of reserves	—	—	—	—
Proved reserves as of December 31, 2004	235	137	—	257
Revisions due to prices	(20)	(2)	—	(20)
Revisions other than price	17	2	—	17
Extensions and discoveries	6	—	—	6
Purchase of reserves	—	—	—	—
Production	(24)	(11)	—	(26)
Sale of reserves	—	—	—	—
Proved reserves as of December 31, 2005	214	126	—	234
Revisions due to prices	(2)	(2)	—	(2)
Revisions other than price	6	(11)	—	5
Extensions and discoveries	14	—	—	14
Purchase of reserves	—	—	—	—
Production	(23)	(8)	—	(24)
Sale of reserves	—	—	—	—
Proved reserves as of December 31, 2006	209	105	—	227
Proved developed reserves as of:				
December 31, 2003	98	81	—	111
December 31, 2004	109	71	—	119
December 31, 2005	103	60	—	111
December 31, 2006	99	42	—	106

(1) Except for nine MMBoe of proved reserves as of December 31, 2006, the preceding International quantities of reserves are attributable to production sharing contracts with various foreign governments.

Noteworthy amounts included in the categories of proved reserve changes for the years 2006, 2005 and 2004 in the above tables include:

Extensions and Discoveries Of the 433 MMBoe of 2006 extensions and discoveries, 143 MMBoe related to the Barnett Shale area in Texas, 88 MMBoe related to the Jackfish steam-assisted gravity drainage project in Canada which is expected to begin production in 2007, 30 MMBoe related to the Carthage area in east Texas and 20 MMBoe related to the Washakie area in southern Wyoming.

The 2006 extensions and discoveries included 202 MMBoe related to additions from Devon's infill drilling activities, including 127 MMBoe related to the Barnett Shale area and 20 MMBoe related to the Lloydminster area in Canada.

Of the 400 MMBoe of 2005 extensions and discoveries, 118 MMBoe related to Jackfish, 54 MMBoe related to the Barnett Shale, and 40 MMBoe related to the Deep Basin in Canada. The 2005 extensions and discoveries included 76 MMBoe related to additions from Devon's infill drilling activities, including 19 MMBoe related to the Barnett Shale, 16 MMBoe related to Carthage and eight MMBoe related to the Permian Basin in New Mexico and west Texas.

Of the 266 MMBoe of 2004 extensions and discoveries, 32 MMBoe related to the Canadian Deep Basin, 29 MMBoe related to the Barnett Shale, and 28 MMBoe related to Carthage. The 2004 extensions and discoveries included 67 MMBoe related to additions from Devon's infill drilling activities, including 21 MMBoe related to Carthage, 12 MMBoe related to the Permian Basin and nine MMBoe related to the Barnett Shale.

Purchase of Reserves The 2006 total includes 100 MMBoe located in the Barnett Shale that was acquired in the Chief acquisition. See Note 3.

Sale of Reserves The 2005 total includes 176 MMBoe of reserves related to non-core oil and gas properties in the offshore Gulf of Mexico and onshore in the United States and Canada. See Note 3.

Standardized Measure of Discounted Future Net Cash Flows

The tables below reflect the standardized measure of discounted future net cash flows relating to Devon's interest in proved reserves:

TOTAL DECEMBER 31, (IN MILLIONS)	2006	2005	2004
Future cash inflows	$ 82,354	94,132	66,595
Future costs:			
Development	(8,518)	(5,802)	(4,211)
Production	(29,408)	(25,063)	(19,513)
Future income tax expense	(13,856)	(21,425)	(13,704)
Future net cash flows	30,572	41,842	29,167
10% discount to reflect timing of cash flows	(13,999)	(18,784)	(13,555)
Standardized measure of discounted future net cash flows	$ 16,573	23,058	15,612

DOMESTIC DECEMBER 31, (IN MILLIONS)	2006	2005	2004
Future cash inflows	$ 47,980	55,954	39,214
Future costs:			
Development	(4,919)	(2,954)	(2,208)
Production	(18,858)	(16,213)	(13,181)
Future income tax expense	(7,588)	(12,582)	(7,597)
Future net cash flows	16,615	24,205	16,228
10% discount to reflect timing of cash flows	(7,938)	(11,258)	(7,129)
Standardized measure of discounted future net cash flows	$ 8,677	12,947	9,099

CANADA DECEMBER 31, (IN MILLIONS)	2006	2005	2004
Future cash inflows	$ 22,575	26,277	18,483
Future costs:			
Development	(2,395)	(1,984)	(1,353)
Production	(7,431)	(6,344)	(4,285)
Future income tax expense	(3,614)	(5,986)	(4,200)
Future net cash flows	9,135	11,963	8,645
10% discount to reflect timing of cash flows	(4,318)	(5,332)	(4,764)
Standardized measure of discounted future net cash flows	$ 4,817	6,631	3,881

INTERNATIONAL DECEMBER 31, (IN MILLIONS)	2006	2005	2004
Future cash inflows	$ 11,799	11,901	8,898
Future costs:			
Development	(1,204)	(864)	(650)
Production	(3,119)	(2,506)	(2,047)
Future income tax expense	(2,654)	(2,857)	(1,907)
Future net cash flows	4,822	5,674	4,294
10% discount to reflect timing of cash flows	(1,743)	(2,194)	(1,662)
Standardized measure of discounted future net cash flows	$ 3,079	3,480	2,632

Future cash inflows are computed by applying year-end prices (averaging $46.11 per barrel of oil, $5.06 per Mcf of gas and $27.63 per barrel of natural gas liquids at December 31, 2006) to the year-end quantities of proved reserves, except in those instances where fixed and determinable price changes are provided by contractual arrangements in existence at year-end.

Future development and production costs are computed by estimating the expenditures to be incurred in developing and producing proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. Of the $8.5 billion of future development costs, $2.2 billion, $1.5 billion and $0.9 billion are estimated to be spent in 2007, 2008 and 2009, respectively.

Future development costs include not only development costs, but also future dismantlement, abandonment and rehabilitation costs. Included as part of the $8.5 billion of future development costs are $1.7 billion of future dismantlement, abandonment and rehabilitation costs.

Future production costs include general and administrative expenses directly related to oil and gas producing activities. Future income tax expenses are computed by applying the appropriate statutory tax rates to the future pre-tax net cash flows relating to proved reserves, net of the tax basis of the properties involved. The future income tax expenses give effect to permanent differences and tax credits, but do not reflect the impact of future operations.

Changes Relating to the Standardized Measure of Discounted Future Net Cash Flows

Principal changes in the standardized measure of discounted future net cash flows attributable to Devon's proved reserves are as follows:

	YEAR ENDED DECEMBER 31,		
	2006	2005	2004
		(IN MILLIONS)	
Beginning balance	$ 23,058	15,612	15,769
Oil, gas and NGL sales, net of production costs	(6,895)	(7,064)	(5,767)
Net changes in prices and production costs	(10,519)	11,767	2,027
Extensions and discoveries, net of future development costs	4,579	6,096	3,022
Purchase of reserves, net of future development costs	786	67	31
Development costs incurred during the period which reduced future development costs	1,691	778	681
Revisions of quantity estimates	(2,325)	(799)	(1,105)
Sales of reserves in place	(10)	(2,897)	(13)
Accretion of discount	3,482	2,270	2,243
Net change in income taxes	4,247	(4,691)	(1,580)
Other, primarily changes in timing and foreign exchange rates	(1,521)	1,919	304
Ending balance	$ 16,573	23,058	15,612

16. SUPPLEMENTAL QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Following is a summary of the unaudited interim results of operations for the years ended December 31, 2006 and 2005.

		2006				
		FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER	FULL YEAR
		(N MILLIONS, EXCEPT PER SHARE AMOUNTS)				
Oil, gas and NGL sales	$	2,222	2,192	2,279	2,193	8,886
Total revenues	$	2,684	2,589	2,696	2,609	10,578
Net earnings	$	700	859	705	582	2,846
Net earnings per common share:						
Basic	$	1.58	1.94	1.59	1.31	6.42
Diluted	$	1.56	1.92	1.57	1.29	6.34

		2005				
		FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER	FULL YEAR
		(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)				
Oil, gas and NGL sales	$	1,914	2,048	2,262	2,606	8,830
Total revenues	$	2,330	2,437	2,667	3,188	10,622
Net earnings	$	563	653	744	970	2,930
Net earnings per common share:						
Basic	$	1.17	1.40	1.66	2.18	6.38
Diluted	$	1.14	1.38	1.63	2.14	6.26

The first, second and third quarters of 2006 include $85 million, $16 million and $20 million, respectively, of reductions of carrying values of oil and gas properties. The after-tax effects of these amounts were $85 million (or $0.19 per share), $16 million (or $0.04 per share) and $10 million (or $0.02 per share), respectively. Also, the second quarter of 2006 included a reduction to income tax expense of $243 million (or $0.55 per share) due to statutory rate reductions in Canada and additional income tax expense of $39 million (or $0.09 per share) due to a new income-based tax enacted by the state of Texas.

The adoption of FASB Statement No. 158 in the fourth quarter of 2006 (see Note 6) had no effect on earnings from continuing operations, net earnings or related per share amounts during any of the quarterly periods in 2006.

The fourth quarter of 2005 includes a $212 million reduction of carrying value of oil and gas properties and a $14 million income tax benefit due to a statutory rate reduction in Canada. The after-tax effect of the reduction of carrying value was $161 million, or $0.36 per share. The per share effect of the rate reduction tax benefit was $0.03.

Oil, gas and natural gas liquids sales for the first, second, third and fourth quarters of 2006 exclude $34 million, $27 million, $25 million and $32 million, respectively, related to discontinued operations in Egypt. Oil, gas and natural gas liquids sales for the first, second, third and fourth quarters of 2005 exclude $21 million, $31 million, $37 million and $30 million, respectively, related to discontinued operations in Egypt.

Risk Factors to Forward-Looking Estimates

The forward-looking estimates beginning on page 52 are based on management's examination of historical operating trends, the information which was used to prepare the December 31, 2006, reserve reports and other data in Devon's possession or available from third parties. Devon cautions that its future oil, natural gas and NGL production, revenues and expenses are subject to all of the risks and uncertainties normally incident to the exploration for and development, production and sale of oil, gas and NGLs. These risks include, but are not limited to, price volatility, inflation or lack of availability of goods and services, environmental risks, drilling risks, regulatory changes, the uncertainty inherent in estimating future oil and gas production or reserves, and other risks as outlined below. The production, transportation, processing and marketing of oil, natural gas and NGLs are complex processes which are subject to disruption due to transportation and processing availability, mechanical failure, human error, meteorological events including, but not limited to, hurricanes, and numerous other factors.

Price Volatility

Prices for oil, natural gas and NGLs are determined primarily by prevailing market conditions. Market conditions for these products are influenced by regional and worldwide economic conditions, weather and other local market conditions. These factors are beyond Devon's control and are difficult to predict. In addition to volatility in general, oil, gas and NGL prices may vary considerably due to differences between regional markets, differing quality of oil produced (i.e., sweet crude versus heavy or sour crude), differing Btu contents of gas produced, transportation availability and costs and demand for the various products derived from oil, natural gas and NGLs. Substantially all of Devon's revenues are attributable to sales, processing and transportation of these three commodities. Consequently, Devon's financial results and resources are highly influenced by price volatility.

Oil, Gas, and NGL Production

Estimates for future production of oil, natural gas and NGLs are based on the assumption that market demand and prices for oil, gas and NGLs will continue at levels that allow for profitable production of these products. There can be no assurance of such stability. Most of Devon's Canadian production of oil, natural gas and NGLs is subject to government royalties that fluctuate with prices. Thus, price fluctuations can affect reported production. Also, Devon's international production of oil, natural gas and NGLs is governed by payout agreements with the governments of the countries in which Devon operates. If the payout under these agreements is attained earlier than projected, Devon's net production and proved reserves in such areas could be reduced.

Marketing and Midstream

Estimates for future processing and transport of oil, natural gas and NGLs are based on the assumption that market demand and prices for oil, gas and NGLs will continue at levels that allow for profitable processing and transport of these products. There can be no assurance of such stability. Additionally, Devon cautions that its future marketing and midstream revenues and expenses are subject to all of the risks and uncertainties normally incident to the marketing and midstream business. These risks include, but are not limited to, price volatility, environmental risks, regulatory changes, the uncertainty inherent in estimating future processing volumes and pipeline throughput, cost of goods and services and other risks as outlined herein.

Foreign Exchange

Also, the financial results of Devon's foreign operations are subject to currency exchange rate risks. Unless otherwise noted, all of the dollar amounts are expressed in U.S. dollars. Amounts related to Canadian operations have been converted to U.S. dollars using a projected average 2007 exchange rate of $0.89 U.S. dollar to $1.00 Canadian dollar. The actual 2007 exchange rate may vary materially from this estimate. Such variations could have a material effect on our forward-looking estimates.

Property Acquisitions and Dispositions

Although Devon has completed several major property acquisitions and dispositions in recent years, these transactions are opportunity driven. Except for the planned divestitures of Devon's assets in Egypt and West Africa, the forward-looking estimates do not include the financial and operating effects of potential property acquisitions or divestitures during the year 2007.

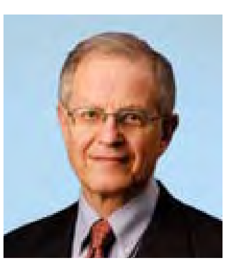
Directors

John W. Nichols, 92, is a co-founder of Devon. He was named chairman emeritus in 1999. Nichols was chairman of the board of directors from the time Devon began operations in 1971 until 1999. He is a founding partner of Blackwood & Nichols Co., which put together the first public oil and gas drilling fund ever registered with the Securities and Exchange Commission. Nichols is a non-practicing Certified Public Accountant.

J. Larry Nichols, 64, is a co-founder of Devon and has been a director since 1971. He was named chairman of the board of directors in 2000 and serves as chairman of the Dividend Committee. Nichols served as president from 1976 until 2003 and has been chief executive officer since 1980. Nichols serves as a director of Baker Hughes Inc. and Sonic Corp. Nichols has a Bachelor of Arts degree in Geology from Princeton University and a law degree from the University of Michigan.

Thomas F. Ferguson, 70, joined the board of directors in 1982 and serves as chairman of the Audit Committee. Ferguson retired in 2005 from his position as managing director of United Gulf Management Ltd., a wholly-owned subsidiary of Kuwait Investment Projects Co. KSC. He has represented Kuwait Investment Projects Co. on the boards of various companies in which it invests, including Baltic Transit Bank in Latvia and Tunis International Bank in Tunisia. Ferguson is a Canadian qualified Certified General Accountant and was formerly employed by the Economist Intelligence Unit of London as a financial consultant.

Peter J. Fluor, 59, joined the board of directors in 2003. Fluor served as a director of Ocean Energy Inc. from 1980 to 2003 and has been chairman and chief executive officer of Texas Crude Energy Inc., a private oil and gas company, since January 2001. From 1997 through 2000, Fluor was president and chief executive officer of Texas Crude Energy Inc. He also serves as lead independent director of Fluor Corp. and is a director of Cameron Corp.



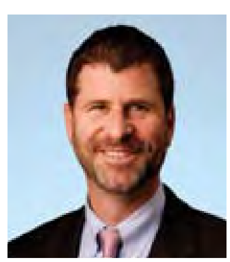
David M. Gavrin, 72, joined the board of directors in 1979 and is lead director and chairman of the Compensation Committee. Gavrin has been a private investor since 1989 and is a director and chairman of the board of MetBank Holding Corp. He is also president and a director of Arthur J. Gavrin Foundation Inc. From 1978 to 1988, he was a general partner of Windcrest Partners, a private investment partnership in New York City, and, for 14 years prior to that, he was an officer of Drexel Burnham Lambert Inc.

John A. Hill, 65, joined the board of directors in 2000 following Devon's merger with Santa Fe Snyder Corp. and serves as chairman of the Governance Committee. He has been with First Reserve Corp., an oil and gas investment management company, since 1983 and is currently its vice chairman and managing director. Prior to creating First Reserve Corp., Hill was president and chief executive officer of several investment banking and asset management companies and served as the deputy administrator of the Federal Energy Administration during the Ford Administration. Hill is chairman of the board of trustees of the Putnam Funds in Boston, a trustee of Sarah Lawrence College and director of various companies controlled by First Reserve Corp.

Robert L. Howard, 70, joined the board of directors in 2003 and is chairman of the Reserves Committee. Howard served as a director of Ocean Energy Inc. from 1996 to 2003. He retired in 1995 from his position as vice president of Domestic Operations, Exploration and Production, of Shell Oil Co. Howard is also a director of Southwestern Energy Co. and McDermott International Inc.

William J. Johnson, 72, has been on the board of directors since 1999. Johnson has been a private consultant to the oil and gas industry since 1994. He is president and a director of JonLoc Inc., an oil and gas company of which he and his family are the only stockholders. Johnson has served as a director of Tesoro Corp. since 1996. From 1991 to 1994, Johnson was president, chief operating officer and a director of Apache Corp.

Michael M. Kanovsky, 58, joined the board of directors in 1998. He was a co-founder of Northstar Energy Corp. and served on Northstar's board of directors from 1982 to 1998. He is president of Sky Energy Corp. and serves as a director of Kinwest Energy Corp. and North American Oil Sands Corp., all privately held energy corporations. Kanovsky also is a director of Accrete Energy Inc., ARC Resources Ltd., Bonavista Petroleum Ltd., Pure Technologies Ltd. and TransAlta Corp.



J. Todd Mitchell, 48, joined the board of directors in 2002. He served as president of GPM Inc., a family-owned investment company, from 1998 to 2006, and currently serves as its vice president for strategic planning. He also has served as president of Dolomite Resources Inc., a privately owned mineral exploration and investments company, since 1987 and as chairman of Rock Solid Images, a privately owned seismic data analysis software company, since 1998. Mitchell was on the board of directors of Mitchell Energy & Development Corp. from 1993 to 2002.

Senior Officers

John Richels, 56, was elected president of Devon in 2004. He previously served as a senior vice president of Devon and president and chief executive officer of Devon's Canadian subsidiary. Richels joined Devon through its 1998 acquisition of Canadian-based Northstar Energy Corp. Prior to joining Northstar, Richels was managing and chief operating partner of the Canadian-based national law firm, Bennett Jones. While employed at Bennett Jones in the 1980s, Richels served as general counsel of the XV Olympic Winter Games Organizing Committee in Calgary. Richels also has served as a director of a number of publicly traded companies. He holds a bachelor's degree in economics from York University and a law degree from the University of Windsor.

Stephen J. Hadden, 52, was elected to the position of senior vice president, Exploration and Production, in 2004. In 1977, Hadden joined Texaco, now Chevron Corp., as a field engineer, subsequently holding a series of engineering and management positions in the United States. He served as vice president of Texaco Exploration and Production and as vice president of the company's California business unit. In 2002, he became an independent consultant. Hadden received a Bachelor of Science degree in chemical engineering from Pennsylvania State University.

Marian J. Moon, 56, was elected to the position of senior vice president, Administration, in 1999. Moon is responsible for office administration, information technology, human resources, corporate resources and corporate governance. Moon has been with Devon for 22 years and served in various capacities, including manager of Corporate Finance and corporate secretary. Prior to joining Devon, Moon was employed by Amarex Inc., an Oklahoma City-based oil and natural gas production and exploration firm, where her last position was treasurer. Moon is a member of the Society of Corporate Secretaries & Governance Professionals and a graduate of Valparaiso University.

Darryl G. Smette, 59, was elected to the position of senior vice president, Marketing and Midstream, in 1999. Smette previously held the position of vice president, Marketing and Administrative Planning. His marketing background includes 15 years with Energy Reserves Group Inc./BHP Petroleum (Americas) Inc. He is also an oil and gas industry instructor, approved by the University of Texas Department of Continuing Education. Smette is a member of the Oklahoma Independent Producers Association, Natural Gas Association of Oklahoma and the American Gas Association. He holds an undergraduate degree from Minot State University and a master's degree from Wichita State University.

Lyndon C. Taylor, 48, was elected to the position of senior vice president and general counsel in February 2007. Taylor had served as Devon's deputy general counsel since August 2005. Prior to joining Devon, Taylor was with Skadden, Arps, Slate, Meagher & Flom, LLP for 20 years, most recently as managing partner of the Houston office's energy practice. He is admitted to practice law in Oklahoma and Texas. Taylor holds a Bachelor of Science degree in industrial engineering from Oklahoma State University and a law degree from the University of Oklahoma.

Glossary

Bitumen / A viscous, tar-like oil that requires nonconventional production methods such as mining or steam-assisted gravity drainage.

Block / Refers to a contiguous leasehold position. In federal offshore waters, a block is typically 5,000 acres.

British thermal unit (Btu) / A measure of heat value. An Mcf of natural gas is roughly equal to one million Btu.

Coalbed natural gas / An unconventional gas resource that is present in certain coal deposits.

Deep water / In offshore areas, water depths of greater than 600 feet.

Delineation well / A well drilled just outside the proved area of an oil or gas reservoir in an attempt to extend the known boundaries of the reservoir.

Development well / A well drilled within the area of an oil or gas reservoir known to be productive. Development wells are relatively low risk.

Dry hole / A well found to be incapable of producing oil or gas in sufficient quantities to justify completion.

Exploitation / Various methods of optimizing oil and gas production or establishing additional reserves from producing properties through additional drilling or the application of new technology.

Exploratory well / A well drilled in an unproved area, either to find a new oil or gas reservoir or to extend a known reservoir. Sometimes referred to as a wildcat.

Field / A geographical area under which one or more oil or gas reservoirs lie.

Floating production, storage and offloading unit (FPSO) / A moored tanker-type vessel used to develop an offshore oil field. Oil is stored within the FPSO until offloaded to a tanker for transportation to a terminal or refinery.

Formation / An identifiable layer of rocks named after the geographical location of its first discovery and dominant rock type.

Fracture, refracture / The process of applying hydraulic pressure to an oil or gas bearing geological formation to crack the formation and stimulate the release of oil and gas.

Gross acres / The total number of acres in which one owns a working interest.

Hedge / A financial contract entered into to manage commodity price risk.

Increased density/infill / A well drilled in addition to the number of wells permitted under initial spacing regulations, used to enhance or accelerate recovery, or prevent the loss of proved reserves.

Independent producer / A non-integrated oil and gas producer with no refining or retail marketing operations.

Lease / A legal contract that specifies the terms of the business relationship between an energy company and a landowner or mineral rights holder on a particular tract.

London Inter Bank Offering Rate (LIBOR) / An average of the interest rate on dollar-denominated deposits, also known as Eurodollars, traded between banks in London.

Natural gas liquids (NGLs) / Liquid hydrocarbons that are extracted and separated from the natural gas stream. NGL products include ethane, propane, butane and natural gasoline.

Net acres / Gross acres multiplied by one's fractional working interest in the property.

New York Mercantile Exchange (NYMEX) / The world's largest physical commodity futures exchange. The prices quoted for oil, gas and other commodity transactions on the exchange are the basis for prices paid throughout the world.

Oil sands / A complex mixture of sand, water and clay trapping very heavy oil known as bitumen.

Pilot program / A small-scale test project used to assess the viability of a concept prior to committing significant capital to a large-scale project.

Production / Natural resources, such as oil or gas, taken out of the ground.

Gross production / Total production before deducting royalties.

Net production / Gross production, minus royalties, multiplied by one's fractional working interest.

Prospect / An area designated for the potential drilling of development or exploratory wells.

Proved reserves / Estimates of oil, gas and NGL quantities thought to be recoverable from known reservoirs under existing economic and operating conditions.

Recavitate / The process of applying pressure surges on the coal formation at the bottom of a well in order to increase fracturing, enlarge the bottomhole cavity and thereby increase gas production.

Recompletion / The modification of an existing well for the purpose of producing oil or gas from a different producing formation.

Reservoir / A rock formation or trap containing oil and/or natural gas.

Royalty / The owner's share of the value of minerals (oil and gas) produced on the property.

Seismic / A tool for identifying underground accumulations of oil or gas by sending energy waves or sound waves into the earth and recording the wave reflections. Results indicate the type, size, shape and depth of subsurface rock formations. 2-D seismic provides two-dimensional information while 3-D creates three-dimensional pictures. 4-C, or four-component, seismic utilizes measurement and interpretation of shear wave data. 4-C seismic improves the resolution of seismic images below shallow gas deposits.

Steam-assisted gravity drainage (SAGD) / A method of extracting bitumen from oil sands. Steam is injected under ground, softening the bitumen and allowing it to flow to the surface.

Undeveloped acreage / Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or gas.

Unit / A contiguous parcel of land deemed to cover one or more common reservoirs, as determined by state or federal regulations. Unit interest owners generally share proportionately in costs and revenues.

Working interest / The cost-bearing ownership share of an oil or gas lease.

Workover / The process of conducting remedial work, such as cleaning out a well bore, to increase or restore production.

VOLUME ACRONYMS

Bbl / A standard oil measurement that equals one barrel (42 U.S. gallons).

MBbl / One thousand barrels

MMBbls / One million barrels

MBbld / One thousand barrels per day

Mcf / A standard measurement unit for volumes of natural gas that equals one thousand cubic feet.

MMcf / One million cubic feet

Bcf / One billion cubic feet

Tcf / One tillion cubic feet

MMcfd / One million cubic feet per day

Boe / A method of equating oil, gas and natural gas liquids. Gas is converted to oil based on its relative energy content at the rate of six Mcf of gas to one barrel of oil. NGLs are converted based upon volume: one barrel of natural gas liquids equals one barrel of oil.

MBoe / One thousand barrels of oil equivalent

MMBoe / One million barrels of oil equivalent

MBoed / One thousand barrels of oil equivalent per day

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E-mail: DevonRevenueHotline@dvn.com

Shareholder Assistance
For information about transfer or exchange of shares, dividends, address changes, account consolidation, multiple mailings, lost certificates and Form 1099:

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Securities Transfer Division
928 Grand Boulevard
Kansas City, MO 64106
Toll free: (877) 860-5820
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Publications
A copy of Devon's annual report to the Securities and Exchange Commission (Form 10-K) and other publications are available at no charge upon request. Direct requests to:

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Shareholder Services Administrator
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Annual Meeting
Our annual shareholders' meeting will be held at 8 a.m. Central Time on Wednesday, June 6, 2007, on the Third Floor of the Chase Tower, 100 North Broadway, Oklahoma City, OK.

Independent Auditors
KPMG LLP
Oklahoma City, OK

Stock Trading Data
Devon Energy Corporation's common stock is traded on the New York Stock Exchange (symbol: DVN). There are approximately 16,000 shareholders of record.

Common Stock Trading Data

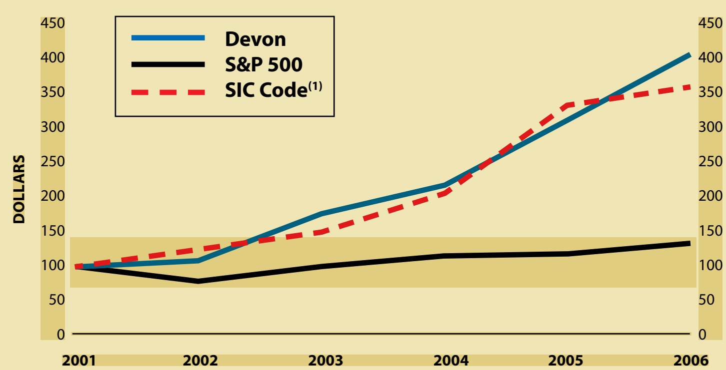
2005

QUARTER	HIGH	LOW	LAST	TOTAL VOLUME
First	$ 49.42	36.48	47.75	195,070,400
Second	$ 52.31	40.60	50.68	222,165,200
Third	$ 70.35	50.75	68.64	184,169,700
Fourth	$ 69.79	54.01	62.54	246,835,700

2006

QUARTER	HIGH	LOW	LAST	TOTAL VOLUME
First	$ 69.97	55.31	61.17	184,716,100
Second	$ 65.25	48.94	60.41	200,005,000
Third	$ 74.65	57.19	63.15	214,743,800
Fourth	$ 74.48	58.55	67.08	174,048,200

Stock Performance – 5-Year Cumulative Total Return

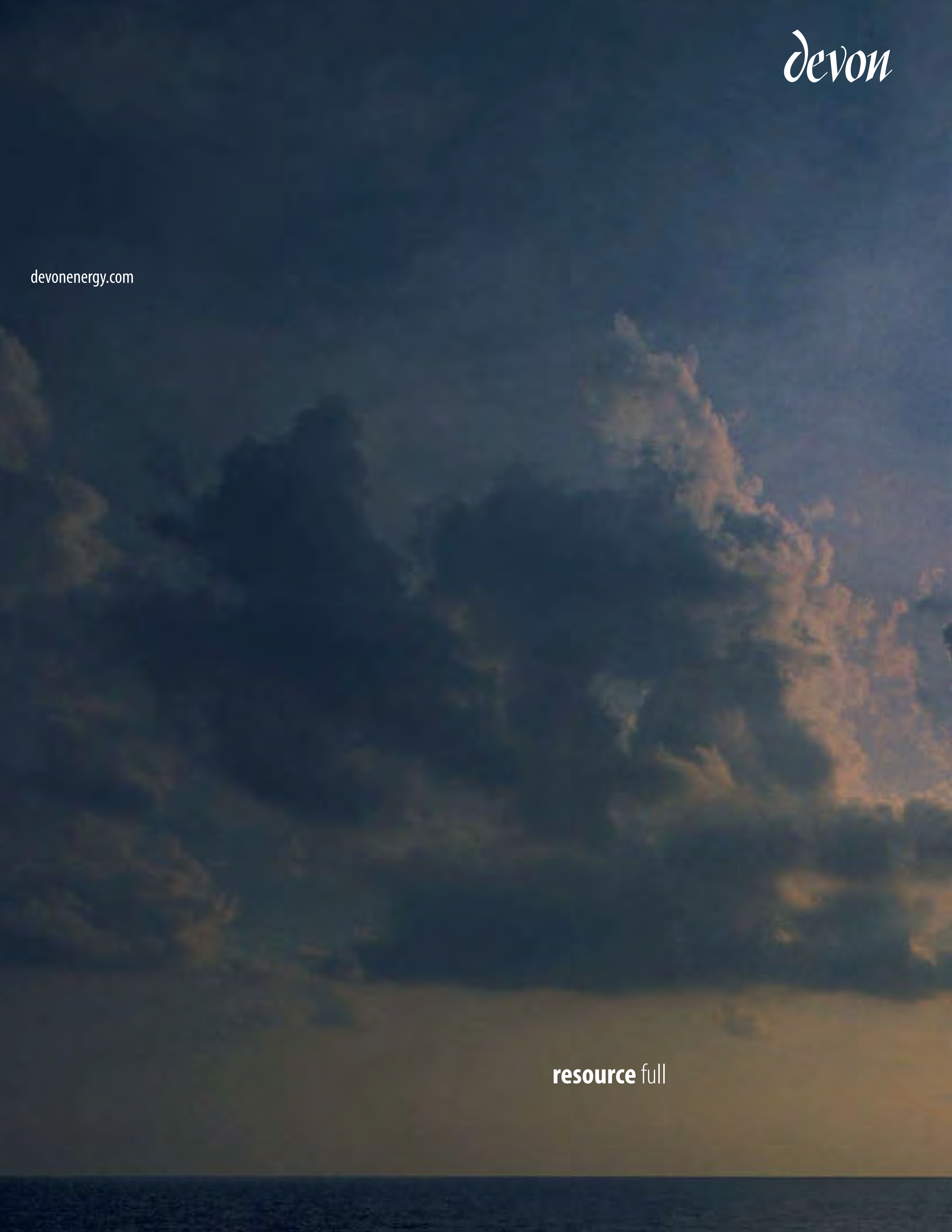


(1) Stock Index for Crude Petroleum and Natural Gas

Certifications The Form 10-K which was filed by the company with the Securities and Exchange Commission (SEC) for the fiscal year ending December 31, 2006 includes as exhibits, the certifications of our Chief Executive Officer and Chief Financial Officer, or persons performing similar functions, required to be filed with the SEC pursuant to Section 302 of the Sarbanes Oxley Act of 2002. The company has also filed with the New York Stock Exchange the 2006 annual certification of its Chief Executive Officer confirming that the company has complied with the New York Stock Exchange corporate governance listing standards.

♲ This annual report was printed on paper containing a minimum of 10% post-consumer fibers.

Forward-Looking Statements This annual report includes "forward-looking statements" as defined by the Securities and Exchange Commission. Such statements are those concerning Devon's plans, expectations and objectives for future operations including reserve potential and exploration target size. These statements address future financial position, business strategy, future capital expenditures, projected oil and gas production and future costs. Devon believes that the expectations reflected in such forward-looking statements are reasonable. However, important risk factors could cause actual results to differ materially from the company's expectations. A discussion of these risk factors can be found on page 101 of this report. Further information is available in the company's Form 10-K and other publicly available reports, which are available free of charge on the company's website, www.devonenergy.com, or will be furnished upon request to the company.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