devon®

2003 ANNUAL REPORT

Beneath the Surface

OUR MISSION

Devon Energy is a results-oriented oil and gas company that builds value for our shareholders through our employees by creating an atmosphere of optimism, teamwork, creativity, resourcefulness and by dealing with everyone in an open and ethical manner.

COMPANY PROFILE

Devon is engaged in oil and gas exploration, production and property acquisitions. Devon is the largest U.S.-based independent oil and gas producer and is one of the largest independent processors of natural gas and natural gas liquids in North America. The company also has operations in selected international areas. Devon is included in the S&P 500 Index and its common shares trade on the American Stock Exchange under the ticker symbol DVN.

Devon's primary goal is to build value per share by:

- *Exploring for undiscovered oil and gas reserves,*
- *Purchasing and exploiting producing oil and gas properties,*
- *Enhancing the value of our production through marketing and midstream activities,*
- *Optimizing production operations to control costs, and*
- *Maintaining a strong balance sheet.*

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 in the "Management's Discussion and Analysis . . ." section 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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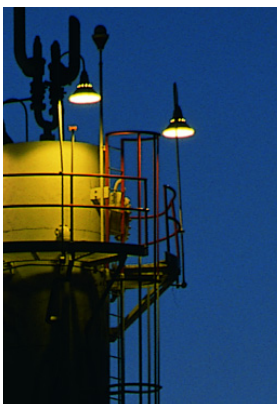
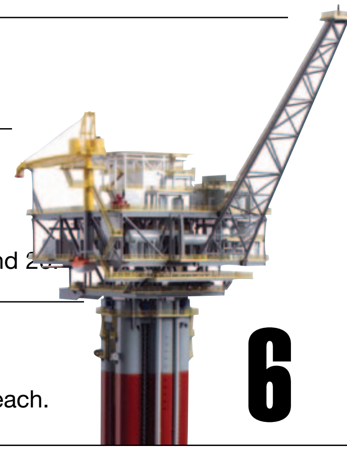


ANNUAL REPORT THEME
"Beneath the Surface" was one of nearly 900 entries from employees in Devon's annual report theme contest. The winning entry was submitted by Doug Bridwell in Bridgeport, Texas.



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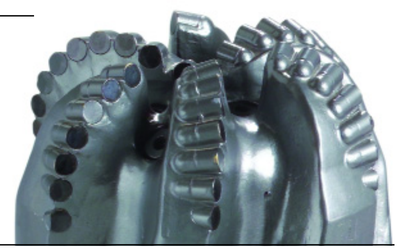
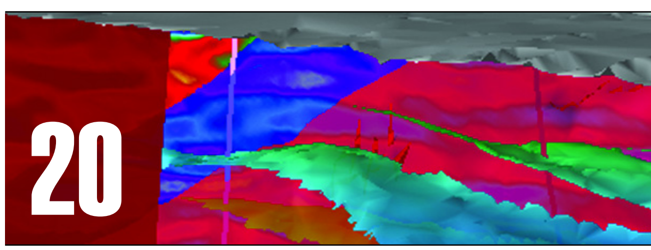


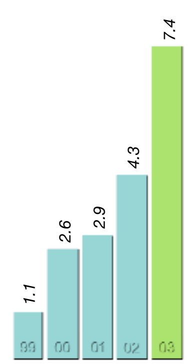


A Look Beneath the Surface Reveals Our Long-term Strategy

DEAR FELLOW SHAREHOLDERS: By many measures, 2003 was the best year in Devon's history. We increased oil and gas production 21%, setting an all-time record. Higher production and stronger prices drove 2003 revenues up 70%, to a record $7.4 billion. Devon's marketing and midstream operations also delivered their best results ever, contributing $286 million to operating margins. Net earnings climbed to $1.7 billion or $8.07 per diluted share—the highest levels in Devon's history. We finished the year with proved reserves of more than two billion equivalent barrels, yet another record.

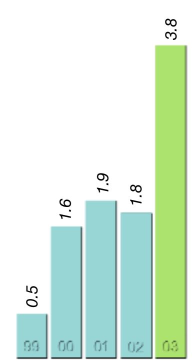
We also had a very good year in 2003 from an operational perspective. We drilled 1,884 successful development wells and 232 exploratory discoveries. One of those discoveries, St. Malo in the deepwater Gulf of Mexico, confirmed a major new hydrocarbon trend. On the development front, we increased production from the Barnett Shale, already the largest natural gas field in Texas, by more than 20%. We launched a multi-year, heavy oil project in Canada with the potential to add 300 million barrels of new oil reserves. Outside North America, we added substantial production volumes in West Africa and China.

Total Revenues
($ Billions)



Strong oil and gas prices and record production drove 2003 revenues ahead 70% to $7.4 billion...

Net Cash Provided by Operating Activities
($ Billions)



...and allowed Devon to more than double net cash provided by operating activities to $3.8 billion.

The record results of 2003 reflect one of our most important accomplishments of the year—our merger with Ocean Energy. Devon merged with Ocean on April 25, 2003, following overwhelming approval by the shareholders of both companies. Former Ocean shareholders received 74 million Devon common shares in exchange for their Ocean shares.

The Ocean merger enhanced our production profile. Ocean brought development projects at Nansen/Boomvang and Zia in the deepwater Gulf of Mexico and the Southern Expansion Area of Zafiro in Equatorial Guinea. Production from these projects supplemented Devon's 2003 production growth from the Barnett Shale in north Texas and our Panyu project in the South China Sea. On a pro forma combined basis, Devon and Ocean increased 2003 production by 5.5% over 2002. We expect to deliver healthy production growth again in 2004—without the benefit of acquisitions. The deepwater Gulf of Mexico development projects at Red Hawk and Magnolia, described elsewhere in this annual report, are scheduled to commence production in the second half of 2004. Devon's share of these projects is expected to bring approximately 20 thousand equivalent barrels per day of new production.

Beyond this immediate production growth, the Ocean merger also brightened Devon's longer-term outlook. Ocean focused on offshore exploration. Through the merger, Devon acquired many talented oil and gas professionals and fortified our exploration inventory. The Ocean assets bolstered Devon's already extensive deepwater Gulf of Mexico acreage position. We now hold more than a million net acres in the deepwater Gulf, the most of any independent. Previous Ocean

▸ **LARRY NICHOLS**
Chairman and CEO

deepwater discoveries at Merganser and Vortex await development and should add reserves and production in the future. Ocean also brought a large inventory of high-potential exploratory blocks offshore West Africa. During 2004 we will test several of these promising international prospects.

Building for the Long Run

Including the 550 million-plus equivalent barrels acquired in the Ocean merger, Devon replaced 321% of 2003 production. We closed the year with 2.1 billion equivalent barrels of proved oil and natural gas reserves. We incurred capital costs, including acquisitions, of $7.9 billion. This resulted in an all-sources cost of $10.82 for each added barrel of reserves. While these 2003 finding and development costs are above industry norms and Devon's historical results, a look beneath the surface reveals our long-term strategy.

During the last three years we have completed three major mergers and acquisitions: Ocean Energy, Mitchell Energy and Anderson Exploration. Each of these companies had significant development projects that Devon assumed. In 2003, we invested $900 million in developing already proved reserves. Simultaneously, we have stepped up our investment in large, multi-year projects. These include a significant exploration effort in the deepwater Gulf and offshore West Africa as well as long-term investments in Canada. In total, we invested about $500 million in 2003 on long cycle-time projects. Most of these projects are designed to provide growth beyond 2004. While these development projects and long-term investments drive up our near-term finding costs, they position Devon to benefit in the future. Devon is now the largest U.S.-based independent oil and gas producer. Our arrival to this position coincides with one of the strongest periods for oil and gas prices in history. This is driving our earnings and cash flow and allowing us to make these investments for the long run. And we are confident that as these longer-term investments begin to add new reserves and production, they will extend our track record of profitable growth.

Deepwater Exploration Gaining Momentum

Over the last five years we have enhanced our deepwater Gulf exploration capacity by integrating the deepwater leases, seismic libraries and technical capabilities of several companies. Our 2003 discoveries increase our excitement about the deepwater Gulf. St. Malo, in the Walker Ridge area of the central Gulf, logged more than 450 net feet of pay. This well, in which Devon has a 22.5% working interest, is Devon's second discovery in the emerging lower Tertiary trend. Our first discovery in the trend was Cascade,

continued on next page

also in the Walker Ridge area. We plan to drill follow-up wells to both St. Malo and Cascade in 2004. If these confirmation wells meet expectations, we will begin to plan for their development. While the discoveries at Cascade and St. Malo have the potential to be meaningful on a stand-alone basis, their significance to Devon is far greater. Through acreage acquired in acquisitions, joint ventures and lease sales, Devon has assembled a large inventory of lower Tertiary prospects. Our early commitment and involvement with this play has provided us an outstanding competitive position.

Financial Strength Deepens

In Devon's 2002 Annual Report we pledged to apply the excess cash we were generating to strengthening our balance sheet. During 2003 we repaid $500 million in debt and increased cash on hand to $1.3 billion at year-end. We also refinanced $500 million of existing long-term debt at a very attractive 2.75% interest rate. Our cash on hand covers 100% of debt repayments planned for 2004 and 2005. Given the current oil and gas price environment, we are continuing to generate cash from operations well in excess of our capital demands. This will allow us to further reduce debt.

Depth of Leadership

John Richels was appointed president of Devon in January 2004. John is a member of Devon's Executive Committee. Following the 1998 merger, he led our Canadian subsidiary, with $8 billion in assets. He is a skilled manager with a thorough understanding of Devon and our industry. Chris Seasons previously reported to John and replaces him as head of our Canadian subsidiary.

Also in 2004, Devon named Brian Jennings chief financial officer. Brian joined Devon in 2000 and serves as senior vice president, corporate finance and development, and is a member of the Executive Committee. As CFO, he assumes responsibility for all financial functions. John, Brian and Chris reflect the depth of leadership Devon has developed throughout the organization.

In conjunction with the Ocean merger, Devon increased the number of directors on its board to 13. Joining Devon's board were former Ocean directors Milton Carroll, Peter Fluor, Robert Howard and Charles Mitchell. Robert Weaver, who had served since 1999, resigned from the board. I welcome our new directors and thank Bob Weaver for his dedicated service.

Also announced in early 2004 were the retirements of two senior executives after lengthy careers with Devon. Mike Lacey, senior vice president, exploration and production, joined the company in 1989. Bill Vaughn, senior vice president, finance, began his career with Devon in 1983. Each was an important contributor to Devon's success, a valued associate and a good friend.

These retirements remind us that change is inevitable. However, it is the things about Devon that have not changed of which I am most proud. We continue to believe in dealing with everyone honestly and ethically. We continue to believe in the powers of creativity, resourcefulness and hard work to uncover hidden opportunities. We continue to believe that to find success, you must look *beneath the surface*. ■

J. Larry Nichols

J. LARRY NICHOLS

Chief Executive Officer and
Chairman of the Board of Directors
March 11, 2004

Five-Year Highlights

Devon's merger with Ocean Energy occurred on April 25, 2003, and was recorded using the purchase method of accounting. Therefore, the information presented below includes Ocean's results from April 25 through December 31, 2003, only.

Year Ended December 31,		1999	2000	2001	2002	2003	LAST YEAR CHANGE
FINANCIAL DATA [1] (Millions, except per share data)							
Total revenues [2]	$	1,140	2,587	2,864	4,316	7,352	70%
Operating costs and expenses		1,309	1,431	2,672	3,775	4,710	25%
Earnings (loss) from operations		(169)	1,156	192	541	2,642	388%
Other expenses		99	118	164	675	397	(41%)
Total income tax expense (benefit)		(75)	377	5	(193)	514	(366%)
Net earnings (loss) from continuing operations		(193)	661	23	59	1,731	2,834%
Net results of discontinued operations		39	69	31	45	-	(100%)
Cumulative effect of change in accounting principle		-	-	49	-	16	NM
Net earnings (loss)		(154)	730	103	104	1,747	1,580%
Preferred stock dividends		4	10	10	10	10	-
Net earnings (loss) applicable to common shareholders	$	(158)	720	93	94	1,737	1,748%
Net earnings (loss) per share:							
Basic	$	(1.68)	5.66	0.73	0.61	8.32	1,264%
Diluted	$	(1.68)	5.50	0.72	0.61	8.07	1,223%
Weighted average common shares outstanding:							
Basic		94	127	128	155	209	35%
Diluted		99	132	130	156	217	39%
Cash flow from continuing operating activities	$	452	1,479	1,776	1,726	3,768	118%
Operating cash flow from discontinued operations		87	110	134	28	-	(100%)
Net cash provided by operating activities	$	539	1,589	1,910	1,754	3,768	115%
Cash dividends per common share [3]	$	0.14	0.17	0.20	0.20	0.20	-

December 31,		1999	2000	2001	2002	2003	LAST YEAR CHANGE
Total assets	$	6,096	6,860	13,184	16,225	27,162	67%
Debentures exchangeable into shares of ChevronTexaco Corporation common stock [4]	$	760	760	649	662	677	2%
Other long-term debt	$	1,656	1,289	5,940	6,900	7,903	15%
Stockholders' equity	$	2,521	3,277	3,259	4,653	11,056	138%
Working capital	$	85	251	435	22	293	1,232%
PROPERTY DATA [1]							
Proved reserves (Net of royalties)							
Oil (MMBbls)		439	406	527	444	661	49%
Gas (Bcf)		2,785	3,045	5,024	5,836	7,316	25%
Natural gas liquids (MMBbls)		55	50	108	192	209	9%
Total (MMBoe) [5]		958	963	1,472	1,609	2,089	30%
10% present value before income taxes (Millions)	$	5,316	17,075	6,687	15,307	22,652	48%
10% present value after income taxes (Millions)	$	4,465	12,065	5,015	10,365	15,921	54%

Year Ended December 31,	1999	2000	2001	2002	2003	LAST YEAR CHANGE
Production (Net of royalties)						
Oil (MMBbls)	25	37	36	42	62	48%
Gas (Bcf)	295	417	489	761	863	13%
Natural gas liquids (MMBbls)	5	7	8	19	22	16%
Total (MMBoe) [5]	79	113	126	188	228	21%

(1) Years 1999 through 2002 exclude results from Devon's operations in Indonesia, Argentina and Egypt that were discontinued in 2002. Devon acquired new assets in Egypt and Indonesia in the April 2003 Ocean merger that are included in Devon's 2003 continuing operations. Data has been reclassified to reflect the 2000 merger of Devon and Santa Fe Snyder in accordance with the pooling-of-interests method of accounting. Revenues, expenses and production in 2003 include only eight and one-fourth months attributable to the Ocean merger; in 2002, include only eleven and one-fourth months attributable to the Mitchell merger; in 2001, include only two and one-half months attributable to the Anderson Exploration acquisition; and in 1999 include only eight months activity attributable to the Snyder Oil transaction and four and one-half months activity attributable to the PennzEnergy transaction.
(2) Excludes other income.
(3) The cash dividends per share presented for years 1999 and 2000 are not representative of the actual amounts paid by Devon because of the 2000 Santa Fe Snyder transaction accounted for as a pooling-of-interests merger. For the years 1999 and 2000, Devon's historical cash dividends per share were $0.20 in each year.
(4) Debentures exchangeable into approximately seven million shares of ChevronTexaco common stock beneficially owned by Devon.
(5) Gas converted to oil at the ratio of 6Mcf:1Bbl. Natural gas liquids converted to oil at the ratio of 1Bbl:1Bbl.
NM Not a meaningful number.

A WORKER POSITIONS *to complete installation of a strake on the Red Hawk cell spar. Strakes deflect ocean currents to minimize the force exerted on the spar structure.*

Q ***What have Devon's mergers and acquisitions accomplished for the company, and are there more deals in your future?***

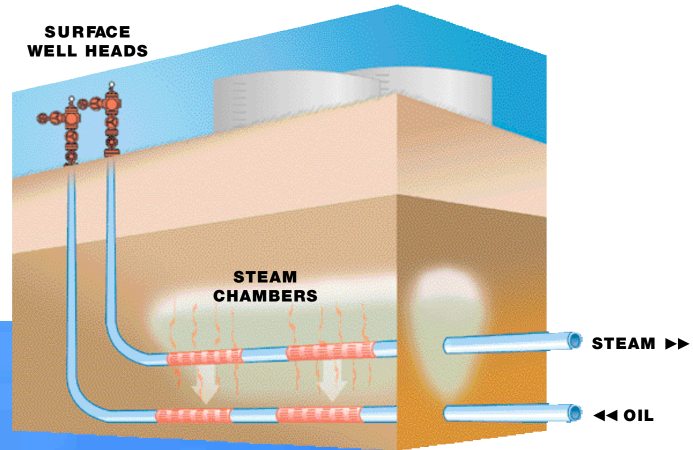
A **LARRY NICHOLS:** *We have used mergers and acquisitions to achieve specific strategic objectives that could not have otherwise been achieved. Our conviction that natural gas was becoming increasingly scarce and valuable drove us to establish more meaningful holdings in North America—prior to the recent uplift in prices. We have achieved that objective. Devon is among the largest independent producers of North American natural gas, and we attained that position at a cost that would be impossible to duplicate today. As a result, we are generating the highest levels of cash flow from operations, earnings and earnings per share in our history.*

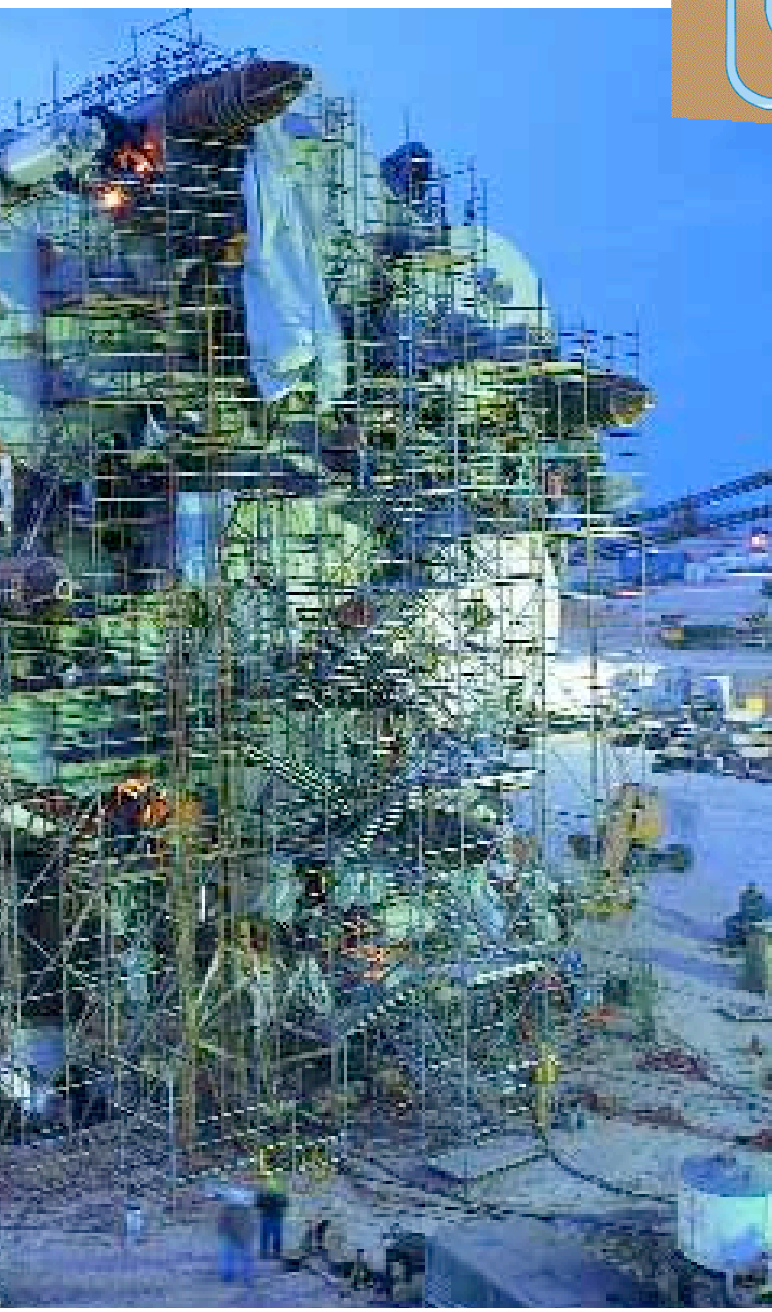
Another objective achieved through M&A is enhanced technical capabilities. We have assembled a highly-skilled workforce with expertise in some of the most innovative technologies employed in our industry. Our acquisition of Mitchell Energy in 2002, gave us the dominant position in the Barnett Shale and the skills to excel in this play. The PennzEnergy acquisition in 1999 gave us offshore exploration and production technology. Our Northstar merger in 1998 gave us thermal heavy oil expertise and the skills to operate in the Western Canadian Sedimentary Basin. Today, we have the ability to pursue opportunities across the spectrum; from non-conventional resources such as heavy oil, coalbed natural gas and black shales to deepwater exploration in the Gulf and abroad.

While we cannot categorically rule out the possibility of another acquisition, Devon is positioned for performance without additional acquisitions. Past transactions have allowed us to establish significant concentrations of high-quality oil and gas properties in some of the most desirable areas. We have taken Devon from a company with only low-risk, low-growth assets, to one with an enviable portfolio of low-risk growth projects balanced by large-scale, high-impact exploration opportunities. And we have the technological capabilities to pursue them. We are no longer dependent upon acquisitions to grow.

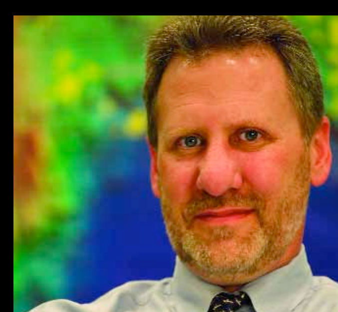
THE MAGNOLIA TENSION-LEG PLATFORM, *when tethered in 4,700 feet of water, will set a water depth record for platforms of this type.*

STEAM-ASSISTED GRAVITY DRAINAGE, *or "SAGD," utilizes injected steam to recover heavy oil reserves beneath the surface of the earth. We are deploying this technology on our Jackfish project in eastern Alberta, Canada. In total, Jackfish is expected to add 300 million barrels of new oil reserves to Devon.*





CONSTRUCTION OF THE RED HAWK *cell spar moves ahead toward a 2004 deployment date. The Red Hawk facility is designed to handle production of 120 million cubic feet of natural gas per day.*



Rick Mitchell's 23 years of oil and gas industry experience came to Devon in the 2003 merger with Ocean Energy. As director of Deepwater Well Engineering and Facilities, Mitchell is responsible for overseeing the company's deepwater projects.

"Devon and its partners are using innovation to access hydrocarbons that were out of reach with previous technology," says Rick. "For example, we are using the world's first cell spar design (shown here) to shorten the development cycle of our Red Hawk field in the deepwater Gulf."

A SCALE MODEL *of the Red Hawk cell spar provides a view of the completed facility. Each of its six mooring cables will extend more than a mile to anchor the massive floating structure to the sea floor.*

LOOKING DEEPER

Devon Promotes Strong Stewardship Initiatives

As a multi-national company with operations that touch thousands of lives in hundreds of communities, Devon is dedicated to environmental stewardship and improvement of the communities in which we are involved.

The oil and gas industry faces many challenges in its effort to meet the world's growing demand for energy. Among them is the preservation of land, water, air and natural habitats. We are proud of our record of environmental stewardship and we value the recognition Devon has earned for taking extra steps to preserve and protect the plants and animals that surround our operations.

Healthy communities allow businesses and their employees to grow and prosper. Charitable giving and support for education and community projects are at the foundation of Devon's effort to be a valued corporate citizen. The well-being of Devon's 4,000-member workforce is also a top priority at Devon. The company's efforts to provide a safe and healthy workplace have earned a strong record of achievement and recognition.

Respecting our Natural Environment

Devon is a partner in the U.S. Environmental Protection Agency's Natural Gas STAR Program, a voluntary effort by government and industry to reduce natural gas emissions. Partners in the program have been successful in reducing methane emissions by more than 275 billion cubic feet since 1993.

In Canada, Devon is active in the Voluntary Challenge and Registry, a partnership between industry and the Canadian government addressing the climate change issue. At the elite Gold Champion level, Devon reports our annual emissions reductions and training and awareness initiatives. Since 1994, Devon has implemented more than 100 emission projects in Canada, eliminating 1.2 million metric tons of carbon dioxide emissions. We expect to eliminate another 700,000 metric tons this year.

▲ **DEVON WORKS TOGETHER** *with ranchers in Wyoming's Powder River Basin to minimize the environmental impact of drilling and production operations.*

IMPROVING HABITAT *at the Sundown Island Bird Sanctuary is a semi-annual volunteer project for Devon employees in Houston.*

Improving our Communities

Devon's investment in communities where it has a strong business presence is broad in scope. While the company plans to donate about $4 million to charity in 2004, our contributions go far beyond financial support. Community involvement is a core value of the company. This is illustrated by volunteerism and support for local initiatives benefiting youth and education programs, health and human services projects, the environment, cultural events and the arts.

In Oklahoma City, more than 125 Devon employees spend one hour per week tutoring students at Mark Twain Elementary School. This school serves one of the community's disadvantaged neighborhoods. Employees serve as role models and mentors as they help students with reading and homework.

For the past three years, employees in Houston have helped enhance the Sundown Island Bird Sanctuary in Matagorda Bay near Port O'Connor, Texas. Volunteers have built nesting platforms, repaired hurricane damage and created bird habitats.

In Canada, Devon has a record of support for education and community programs. Within the past two years, the company and its employees have contributed to efforts ranging from new construction for higher education to new preschool facilities for the underprivileged. Devon's support for community-based initiatives includes the Yellow Fish Road Program, which educates youth and the community at large about water conservation.

Internationally, Devon and its employees support local projects where our business is focused. Those efforts include the A Casa da Arvore project for children in impoverished areas of Rio de Janeiro and repairing buildings and providing supplies and furniture for village schools in Equatorial Guinea.

Health and Safety

The well-being of our employees, contractors and the public are central to Devon's environmental, health and safety philosophy. A tradition of safety is illustrated by a long history of awards for the safe operation of onshore and offshore production facilities and processing plants. Most recently, in 2003, Devon's offshore operations in the Gulf of Mexico received two district SAFE (Safety Award for Excellence) honors from the U.S. Department of the Interior. ■

VOLUNTEER TUTOR *and financial accountant Melanie Mercer reads with Mark Twain elementary student Camisha Brown. Devon teamed with Mark Twain through the Oklahoma City Public Schools Foundation's "Partners in Education" program.*

EXPLORATION AND PRO

Our merger with Ocean in early 2003 established Devon as the largest independent oil and gas producer in the United States. More importantly, Ocean's low-risk development projects and extensive exploration portfolio improved Devon's near-term production profile and enhanced our long-term growth outlook. During 2003, production from the pro forma combined company's oil and gas properties increased by more than 5%. In 2004, we expect our property portfolio to again deliver solid organic production growth. Approximately $1.6 billion, or almost 70% of our 2004 drilling and facilities budget, will be applied to the low-risk development projects that will deliver most of our 2004 production growth.

The lower-risk, near term growth projects are balanced with measured exposure to a variety of high-impact endeavors designed to fuel Devon's growth in the second half of this decade. These longer cycle-time projects pursue objectives of sufficient magnitude to provide meaningful growth—even to a company Devon's size. While these longer-term growth projects require a significant capital outlay and increase near-term costs, they are essential to reload our development inventory for future growth. Fortunately, Devon's producing properties currently provide sufficient cash flow to fund both near-term development projects and longer-term investments.

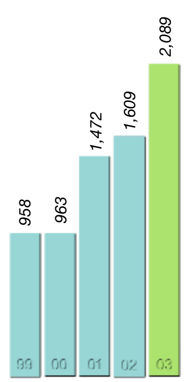
DEEPWATER GULF DEVELOPMENT PROJECTS

Nansen/Boomvang Satellite Discoveries

In the merger with Ocean, Devon acquired interests in two significant deepwater producing properties in the East Breaks area of the Gulf of Mexico. Nansen and Boomvang, completed in 2002, are in about 3,500 feet of water. After the merger, Nansen/Boomvang accounted for approximately 30% of Devon's total Gulf of Mexico oil and gas production.

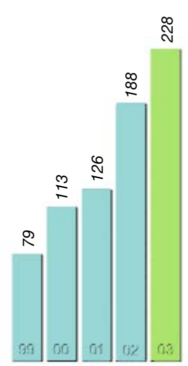
The Nansen/Boomvang complex was designed to provide host facilities for subsequent discoveries on surrounding acreage. In keeping with this hub-and-spoke concept, we drilled several satellite discoveries and began connecting them to the Nansen/Boomvang complex in 2003. In the first quarter of 2004, we are tying in two new wells in the Boomvang area and we expect to add two additional recent discoveries in the third quarter. These satellites add new oil and gas reserves and help maintain a high level of production through these facilities. Devon's current share of production from Nansen/Boomvang is about 42,000 barrels of oil equivalent per day.

Reserves
(Net of Royalties)
(MMBoe)



The Ocean merger and successful drilling drove proved reserves to 2.1 billion equivalent barrels at year-end...

Oil, Gas and NGL Production
(Net of Royalties)
(MMBoe)



...and increased production to 228 million equivalent barrels in 2003.

Red Hawk and Magnolia Moving Ahead

In addition to the established Nansen/Boomvang complex, Ocean had two other deepwater development projects under construction at the time

ODUCTION PORTFOLIO

THE HULL *for the Magnolia tension leg platform is shown under construction in a fabrication yard in Korea. Following its completion in late 2003, the hull was shipped to Corpus Christi, Texas, for mating with the deck. We expect Magnolia to bring Devon more than 10,000 barrels a day of new oil production.*

of the merger. Red Hawk, in 5,300 feet of water, and Magnolia, in 4,700 feet, both lie in the Garden Banks area of the Gulf of Mexico. Devon maintains a 50% working interest in Red Hawk and a 25% interest in Magnolia.

Red Hawk, discovered in 2001, will employ the world's first cell spar, the latest generation of the floating spar concept. Red Hawk's floating hull comprises six steel tubes, or cells, surrounding a seventh center tube. The top of the hull will ride above the water and support the deck. Red Hawk's component construction allowed it to be economically fabricated at a site on the Gulf Coast, relatively close to its eventual mooring place. This innovative approach reduced the required development cycle-time, thereby improving the rate of return.

Devon and its partner drilled, completed and tested the two initial Red Hawk gas wells in 2003. The wells await subsea tie-in to the spar. We expect first production in the third quarter of 2004, with Devon's share in

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Q ***In today's oil and gas price environment, Devon is generating large amounts of excess cash. How do you plan to deploy the surplus?***

A **BRIAN JENNINGS,** ***Senior Vice President and Chief Financial Officer:*** *As evidenced by our record earnings and cash flow in 2003, this is a very good time for Devon and the independent exploration and production sector. Oil and gas supply and demand fundamentals currently favor producers. However, commodity prices can change quickly. Consequently, we must take advantage of the current environment and seize this opportunity to further strengthen our balance sheet.*

In spite of the rapid progress we've made over the last year in building Devon's financial strength, we still view debt repayment as a top priority. At year-end 2003 we had accumulated $1.3 billion in cash earmarked to retire about $340 million of debt in 2004 and $920 million in 2005. We expect to generate excess cash again in 2004 and believe it is prudent to begin to prepare for our 2006 debt maturities. However, as we become satisfied that we have an ample cash cushion for future debt retirement, we will consider alternative uses of cash such as additional dividend increases and repurchasing stock.

the range of 50 to 70 million cubic feet of gas per day. As with Nansen/Boomvang, Red Hawk is designed to be a central processing facility serving future discoveries in the area.

Production facilities for the 1999 Magnolia discovery are nearing completion. Magnolia's 10,000 ton hull, completed in late 2003, was fabricated in Korea and towed by sea to a yard on the Texas coast. Final construction of this tension-leg platform is under way with field installation scheduled for late 2004. We initially plan to bring on two of the nine expected producing wells near year-end. Devon's share of Magnolia's oil and gas production is expected to total 10,000 to 12,000 oil equivalent barrels per day.

INTERNATIONAL DEVELOPMENT PROJECTS

Zafiro Field Gets Bigger

The most significant producing property in Ocean's portfolio was its interest in the Zafiro field, offshore Equatorial Guinea. Zafiro was discovered in 1995. At the time of the merger in April 2003, Devon's share of production was approximately 35,000 barrels per day. In July 2003, we ramped up production dramatically by bringing on new wells in the Zafiro Southern Expansion Area. Zafiro oil is produced into floating production, storage and offloading vessels, or FPSOs. With the addition of the new Serpentina FPSO, field-wide production climbed to a record 302,000 equivalent barrels of oil per day with Devon's share topping 57,000 barrels per day.

Panyu Production on Stream

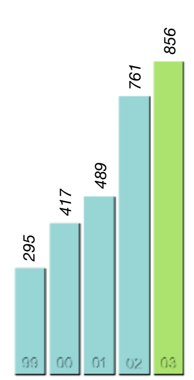
Another source of 2004 production growth is a Devon-operated oil development project in the South China Sea. Late in 2003, we culminated this multi-year development with initial production from the twin Panyu platforms. Devon's share of Panyu production should average about 15,000 barrels per day in 2004.

ACG Field Awaits Main Export Pipeline Completion

The 1,100-mile long, one million barrel per day oil pipeline connecting the Caspian Sea and the Mediterranean is under construction. Its expected completion in 2005 will connect the 4.7 billion barrel ACG field in Azerbaijan to world markets. This will allow production from this super-giant oil field to begin ramping up dramatically. Devon's share of oil production from our 5.6% interest in the ACG field is expected to peak in 2008 or 2009, at more than 50,000 barrels per day.

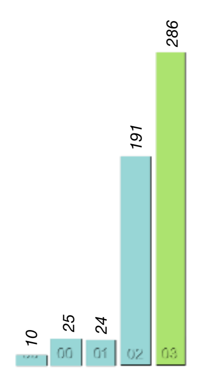
continued on page 16

North American Natural Gas Production
(BCF)



Devon increased North American natural gas production to a record 856 billion cubic feet in 2003.

Marketing and Midstream Margin*
($ Millions)



Greater gas throughput and higher gas and gas liquids prices increased marketing and midstream margin by 50% in 2003.

* Marketing and midstream revenues less operating costs

Q ***Devon's Canadian production declined in 2003. Can the company grow its Canadian production in the future?***

A **JOHN RICHELS, *President:*** *Yes, we can. In 2003, we replaced 110% of our Canadian production with new reserves and we are allocating about $750 million of our 2004 capital budget to Canada. This should translate into significant production growth in 2004.*

Looking beyond 2004, Devon has a tremendous base from which to explore for new oil and gas reserves. We have a large inventory of infill drilling opportunities on our current producing properties in Canada. For example, in many parts of the Deep Basin where Devon is one of the largest producers, our well density is lower than most of our competitors. This provides us with a source of low-risk reserve and production growth for the future. Furthermore, we hold some 10 million net undeveloped acres in Canada—the largest position of any U.S.-based independent. The growth opportunities represented by this acreage position are reflected in our 2004 capital budget with about $250 million devoted to Canadian exploration.

Further out on the growth curve are Devon's Jackfish thermal heavy oil project and Mackenzie Delta gas. Jackfish is expected to start producing in 2006 or 2007 with production reaching 35,000 barrels per day in 2008. These wells have very long productive lives and in aggregate represent 300 million barrels of potential recoverable reserves. Our 2002 gas discovery in the Mackenzie Delta awaits construction of a pipeline that could be built before the end of the decade. Since neither of these projects is contributing to current production or reserves, they are sources of future growth in Canada.

Liquids from Gas

FRACTIONATION TOWERS *at Devon's Bridgeport, Texas, gas plant extract liquids from the natural gas stream. Devon is one of the largest gas processors in North America.*

As natural gas flows from the underground rock formations from which it is produced, it often contains varying quantities of natural gas liquids. Natural gas liquids, also known as NGLs, include ethane, propane, butane, and natural gasoline. These byproducts are used for everything from feedstock for manufacturing chemicals to fuel for backyard grills.

Devon's wells in north Texas can produce as much as four to five gallons of recoverable NGLs from every thousand cubic feet of gas produced. Along the Texas Gulf Coast, recovery rates are generally two to three gallons per thousand cubic feet. Many basins in western Canada also produce liquids-rich gas.

NGLs are generally more valuable when extracted and sold on a stand-alone basis than when left in the gas stream and sold as natural gas. Consequently, an important part of Devon's marketing and midstream business is the extraction and sale of NGLs.

Devon primarily employs the cryogenic method of extracting NGLs. This requires cooling the natural gas stream to as low as minus 150°F. As the temperature is lowered, natural gas liquids condense and separate from the methane gas. The extracted NGLs are then shipped to customers by truck, rail and pipeline. ■

◂ **A DRILLING RIG** *shown at twilight drills a Permian Basin well. Long-lived reserves, typical of the Permian Basin, provide Devon with a stable source of cash flow.*

Q ***How does marketing and midstream contribute to the overall success of the company?***

A **DARRYL SMETTE, Senior Vice President, Marketing and Midstream:** *By owning gas processing assets in areas where we have significant production, we can assure access to ready markets and timely connection of our wells to gathering and processing facilities. This adds stability and predictability to our oil, natural gas and liquids production. Owning significant midstream assets also enhances the company's overall economic returns.*

In 2003, Devon's marketing and midstream operations delivered outstanding results. We increased revenues to $1.5 billion, 46% ahead of 2002. Our operating margin of $286 million was 50% more than in 2002. Higher natural gas and natural gas liquids prices combined with a 25% increase in natural gas throughput volumes led to these results. We also disposed of three non-core assets and improved administrative efficiency by consolidating personnel into our Oklahoma City headquarters. This has allowed us to improve our effectiveness and reduce costs. We expect 2004 to be another very profitable year for the marketing and midstream division. ◗

▴ **THE HAVRE PIPELINE,** *managed by Devon, transports gas from our Bear Paw field in north central Montana. Devon owns interests in more than 13,000 miles of pipelines.*

DRILL BITS *are designed to fit many well configurations and applications. Of more than 2,100 successful wells Devon drilled in 2003, 87% were development wells in North America. Our extensive inventory of low-risk development locations is a stable source of oil and gas production growth.*

CORE SAMPLES *enable geoscientists to better understand underground reservoir characteristics. Effective reservoir management enhances the reliability and predictability of Devon's production profile.*

Joe Huber came to Devon through the 2000 merger with Santa Fe Snyder. He had been with Santa Fe since 1990. As foreman, Joe supervises field operations and production from the Indian Basin field in southeast New Mexico.

"As a 19-year veteran of the energy industry, I'm pleased to work for a company with the strength and stability of Devon."

OUR PANYU PROJECT IN CHINA *will add about 15,000 barrels of oil per day to 2004 production. First production from Panyu was five years after the initial discovery in 1998. In 2003, Devon invested $500 million in long cycle-time projects, such as Panyu. These investments in future production and reserve additions help to stabilize Devon's long-term production outlook.*

THE BARNETT SHALE; MOVING OUTSIDE THE CORE

The Barnett Shale in the Fort Worth Basin of north Texas was the crown jewel of the Mitchell acquisition and is Devon's largest asset. In just a handful of years, the Barnett Shale has grown to become the largest gas field in Texas and one of the largest in North America. We have increased production from the Barnett Shale by two-thirds since announcing the Mitchell acquisition in 2001. At year-end 2003, it was producing about 575 million equivalent cubic feet of gas per day for the company.

The Barnett Shale is a "tight" formation. After drilling, wells must be fracture stimulated to provide paths for the gas to flow into the wellbore. The portion of the field we refer to as the core area is characterized by a limestone barrier at the base of the shale. This barrier stops the hydraulic fractures from penetrating a deeper, water-bearing zone. Most of Devon's 1,600 producing Barnett Shale wells are within this core area.

While most of our current Barnett Shale production comes from within it, the core area represents just 120,000 of Devon's 550,000 net acres in the field. In late 2002 and 2003, Devon began experimenting with horizontal drilling as an approach to avoid the water and move production outside the core. (See inset story on horizontal drilling on next page.) We are encouraged by our horizontal drilling results so far. However, with horizontals representing fewer than 5% of Devon's Barnett Shale wells, we have much to learn. It took Devon, and Mitchell Energy before us, years to perfect the drilling and completion methods that are most effective within the core area. This process is only beginning outside its boundaries. Including horizontal and vertical wells, we plan to drill about 225 Barnett wells in 2004, with more than 50 planned for outside the core.

CANADIAN OIL SANDS...AN INVESTMENT IN THE FUTURE

Devon launched a major Canadian thermal heavy oil development project in 2003. We plan to invest some $400 million over several years in our 100% owned Jackfish project. Western Canada's oil sands, or bitumen deposits, are vast, and Devon holds leases on about 150,000 net acres. Shallow bitumen deposits can be mined at the surface. Others, like Jackfish, are too deep to mine and employ Steam-Assisted Gravity Drainage (SAGD) to extract the bitumen. Devon operates the world's longest-running SAGD facility at Dover, located north of Jackfish.

At Jackfish, we will initially drill 35 pairs of wells into the tar-like bitumen. Steam injected into the upper wells heats the bitumen and allows it to drain into the lower producing wells along with water condensed from the steam. At the surface facilities, bitumen is separated from the water and blended with light crude so it can be pumped through pipelines to market. Government approvals are pending, and we expect to begin constructing the Jackfish facilities in late 2004. We anticipate reaching full production of 35,000 barrels per day in 2008.

GULF OF MEXICO EXPLORATION

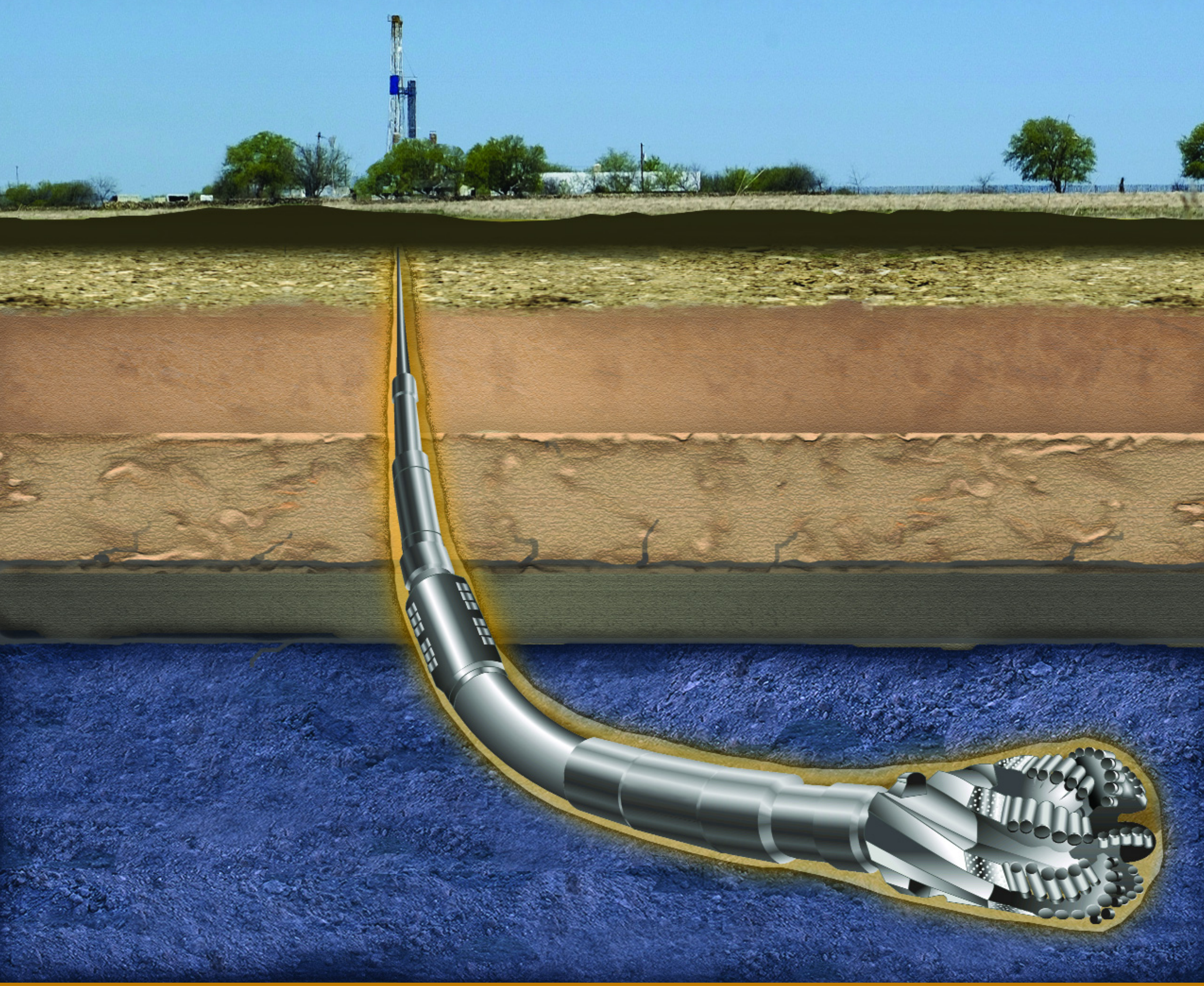
Devon has an interest in 544 exploration blocks in the deepwater Gulf of Mexico—the largest inventory of any independent producer. Because

continued on page 18

Q ***It has been almost a year since the Ocean merger. Have the expected synergies of the merger been realized and is the integration with Ocean complete?***

A **MARIAN J. MOON,** ***Senior Vice President, Administration:*** *We have substantially completed the integration of Ocean and have begun to capture the synergies. At the time of the merger, most of Ocean's employees were in Houston. Because Devon's Gulf of Mexico and international divisions were already located in Houston, we integrated the Ocean staff without extensive employee relocations. During this process, we consolidated all the Houston-area Devon and Ocean employees into Devon's downtown offices. As part of the integration, about 360 full-time positions, with associated annual costs of $30 to $35 million, were eliminated. Ocean also had some long-term contracts for various services that, when eliminated, will generate additional savings over time. Less obvious synergies resulting from Devon's larger size, such as increased purchasing power, superior access to capital and more effective marketing of our oil and gas are also being achieved.*

General and administrative expense per barrel of oil and gas produced is one measure of the synergies of the merger. Based on our full-year forecast, we expect our general and administrative expense in 2004 to be about $1.20 per equivalent barrel of production. This compares with actual general and administrative expense of $1.35 per barrel in 2003. These savings are being achieved in spite of general upward pressure on employment costs.



Beneath the Surface, *Horizontally*

Above ground, horizontal wells appear much like the more common vertical wells. The same drilling rigs can drill both types. It's deep beneath the surface where things change. At a pre-determined depth, the vertical wellbore is steered in a mild arc until it eventually runs parallel to the surface. Horizontal drilling is possible because seemingly rigid steel pipe is actually quite flexible over long spans. Specialized down-hole cutting tools and computerized monitoring systems make it possible to steer the drilling with remarkable precision.

Horizontal drilling isn't new, but 25 years of technological improvements have made it more reliable and cost effective. An advantage of horizontal drilling is that it penetrates more reservoir rock than would be possible with a typical, vertical well. Therefore, more oil or gas is recovered from each well. Drilling costs are usually higher for a horizontal well, but better oil and gas recoveries can more than offset the incremental costs. One horizontal well may take the place of two, three or even more vertical wells. This also means that fewer surface locations are necessary. This is an advantage in populated or environmentally sensitive areas, where minimal surface impact is required. Offshore, directional drilling, of which horizontal drilling is a variant, is essential. Multiple offshore wells are often drilled from and produced through a single fixed platform.

Devon will drill more than 100 horizontal wells this year in its Barnett Shale gas field in north Texas. We believe that horizontal drilling may be a key to unlocking the potential of our 430,000 net acres outside the core Barnett Shale producing area. ■

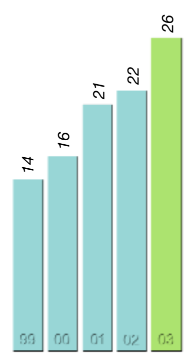
individual deepwater exploration wells require a significant capital investment, we utilize partnerships and joint ventures to limit our exposure to any single project. In this way we gain access to a wide variety of projects and play types without undue risk. Devon generally limits its exposure to participation in six to eight deepwater exploration wells each year. In 2004, three of our deepwater Gulf exploration wells are designed to further delineate discoveries made in 2002 and 2003.

The Emerging Lower Tertiary Trend

In last year's annual report we discussed our deepwater Gulf of Mexico discovery called Cascade. While Cascade appears to be significant, quantifying it further will require more drilling. In 2003, Devon drilled another deepwater discovery approximately 50 miles from Cascade called St. Malo. Both wells are in the Walker Ridge area. These two wells and other recent industry discoveries underpin an emerging exploratory play becoming known as the lower Tertiary trend.

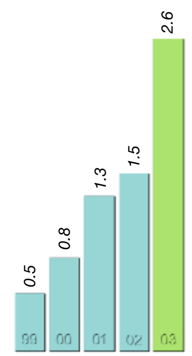
St. Malo, in which Devon has a 22.5% working interest, encountered more than 450 net feet of oil pay over a gross interval of 1,400 feet. In addition to those impressive figures, the lateral extent of the reservoir looks to be very large as well. Additional drilling will define just how large. Devon and our partners in St. Malo plan to drill an appraisal well in 2004. If that well and other delineation steps continue to encourage us, we will begin planning for field development. Because deepwater projects are multi-year undertakings—St. Malo is in 6,900 feet of water—first production is at least four years away. We hope to begin booking reserves for St. Malo in 2004 or 2005.

Net Undeveloped Acreage
(Millions of Acres)



Devon has nearly doubled its inventory of net undeveloped acreage...

Capital Expenditures for Exploration & Development
($ Billions)



...and increased capital expenditures for exploration and development five-fold since 1999.

In 2004, Devon will also participate in an appraisal well to our 2002 Cascade discovery. Our early success at Cascade allowed us to establish a significant position in this emerging play. We have assembled 19 additional lower Tertiary prospects. In addition to delineating our discoveries at Cascade and St. Malo, we expect to test at least two other lower Tertiary prospects during 2004.

About 70 of our more than 500 deepwater acreage blocks are being earned through a joint venture with ChevronTexaco. We are currently drilling the last of the four earning wells in the joint venture; the Jack well will test another lower Tertiary target in the

11-Year Property Data (1)

		1993	1994	1995	1996	1997
Reserves (Net of royalties)						
Oil (MMBbls)		257	294	313	351	219
Gas (Bcf)		709	744	860	1,131	1,403
Natural Gas Liquids (MMBbls)		7	12	16	18	24
Total (MMBoe) (2)		382	430	472	558	477
10% Present Value (Millions) (3)	$	1,074	1,485	1,872	3,952	2,100
Production (Net of royalties)						
Oil (MMBbls)		27	27	28	30	29
Gas (Bcf)		106	101	109	116	180
Natural Gas Liquids (MMBbls)		1	1	1	2	3
Total (MMBoe) (2)		46	45	47	52	62
Average Prices						
Oil (Per Bbl)	$	12.94	12.99	15.07	17.49	17.03
Gas (Per Mcf)	$	1.77	1.69	1.44	1.82	2.04
Natural Gas Liquids (Per Bbl)	$	12.51	10.17	10.62	13.78	12.61
Oil, Gas and Natural Gas Liquids (Per Boe) (2)	$	12.04	11.84	12.49	14.90	14.51
Production and Operating Expense per Boe (2)	$	4.91	4.83	4.69	5.24	4.63

(1) Years 1999 through 2002 exclude results from Devon's operations in Indonesia, Argentina and Egypt that were discontinued in 2002. Devon acquired new assets in Egypt and Indonesia in the April 2003 Ocean merger that are included in Devon's 2003 continuing operations. 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) Gas converted to oil at the ratio of 6Mcf:1Bbl. Natural gas liquids converted to oil at the ratio of 1Bbl:1Bbl.
(3) Before income taxes.

Walker Ridge area, close to St. Malo. Although Jack will complete Devon's obligation under the terms of the joint venture, we expect to continue exploring with ChevronTexaco on this acreage in the future.

Drilling Deeper on the Shelf

Although it's a mature producing region, the Gulf of Mexico's shallow shelf still has life left in it. In 2003, Devon's 11,000-foot Grays discovery on Galveston 424 resulted in three gas wells that came on line in February 2004. Devon's share of production from Grays came in at more than 25 million cubic feet per day. Devon will test two other prospects similar to Grays in 2004.

Exploration of deep formations beneath the shelf is gaining increasing attention within the industry. The "deep shelf" generally refers to wells drilled below 15,000 feet. Recent advances in seismic technology and federal royalty incentives have stimulated deep shelf exploration. In early 2004, Devon made its first deep shelf discovery. The Tikal prospect, Eugene Island 142, encountered 110 feet of net pay below 17,000 feet. Devon has a 30% working interest in this well, which is expected to begin producing mid-year 2004. Devon plans to participate in as many as 10 deep shelf prospects in 2004.

INTERNATIONAL EXPLORATION

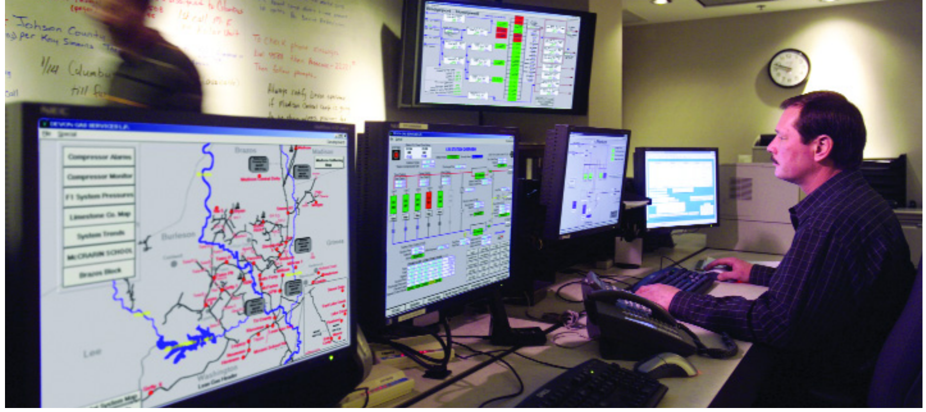
Outside North America, Devon's exploration inventory includes several high-potential licenses offshore West Africa and Brazil. To limit risk, Devon is reducing its interests in several licenses through joint ventures. In 2004, we plan to drill seven exploratory wells on lease blocks in Angola, Equatorial Guinea, Nigeria and Brazil. While the chances of success for any one of these prospects is low, the size of potential discoveries in these areas justifies the risk. In aggregate, these wells will expose Devon to prospects with gross unrisked reserve potential of several billion barrels. ■

Q ***Devon's finding and development costs were high last year and will lead to higher DD&A in 2004. When will these results improve?***

A **LARRY NICHOLS:** *Devon's 2003 all-sources finding and development costs were $10.82 per equivalent barrel. This was about 30% above our five-year average of $8.25 per barrel. Our forecasted increase in unit depreciation, depletion and amortization expense for 2004 is largely a function of these higher finding and development costs.*

The multi-year time horizon of our exploration investments makes it difficult to forecast finding costs for a particular year. That's because discoveries like St. Malo and Cascade in the Gulf of Mexico and Tuk M-18 in the Mackenzie Delta do not immediately increase reserves. We are optimistic that we can begin booking some of these reserves within the next 12 to 18 months, but it's premature to say how this will influence 2004 results. However, we are confident that over time, Devon's finding and development costs will be highly competitive with our peers, as they have been throughout most of our history.

1998	1999	2000	2001	2002	2003	5–YEAR COMPOUND GROWTH RATE	10–YEAR COMPOUND GROWTH RATE
166	439	406	527	444	661	32%	10%
1,440	2,785	3,045	5,024	5,836	7,316	38%	26%
21	55	50	108	192	209	58%	40%
427	958	963	1,472	1,609	2,089	37%	19%
1,375	5,316	17,075	6,687	15,307	22,652	75%	36%
20	25	37	36	42	62	25%	9%
189	295	417	489	761	863	35%	23%
3	5	7	8	19	22	49%	35%
55	79	113	126	188	228	33%	17%
12.28	17.78	24.99	21.41	21.71	25.63	16%	7%
1.78	2.09	3.53	3.84	2.80	4.51	20%	10%
8.08	13.28	20.87	16.99	14.05	18.65	18%	4%
11.09	14.22	22.38	22.19	17.61	25.88	18%	8%
4.29	4.15	4.81	5.29	4.71	5.63	6%	1%

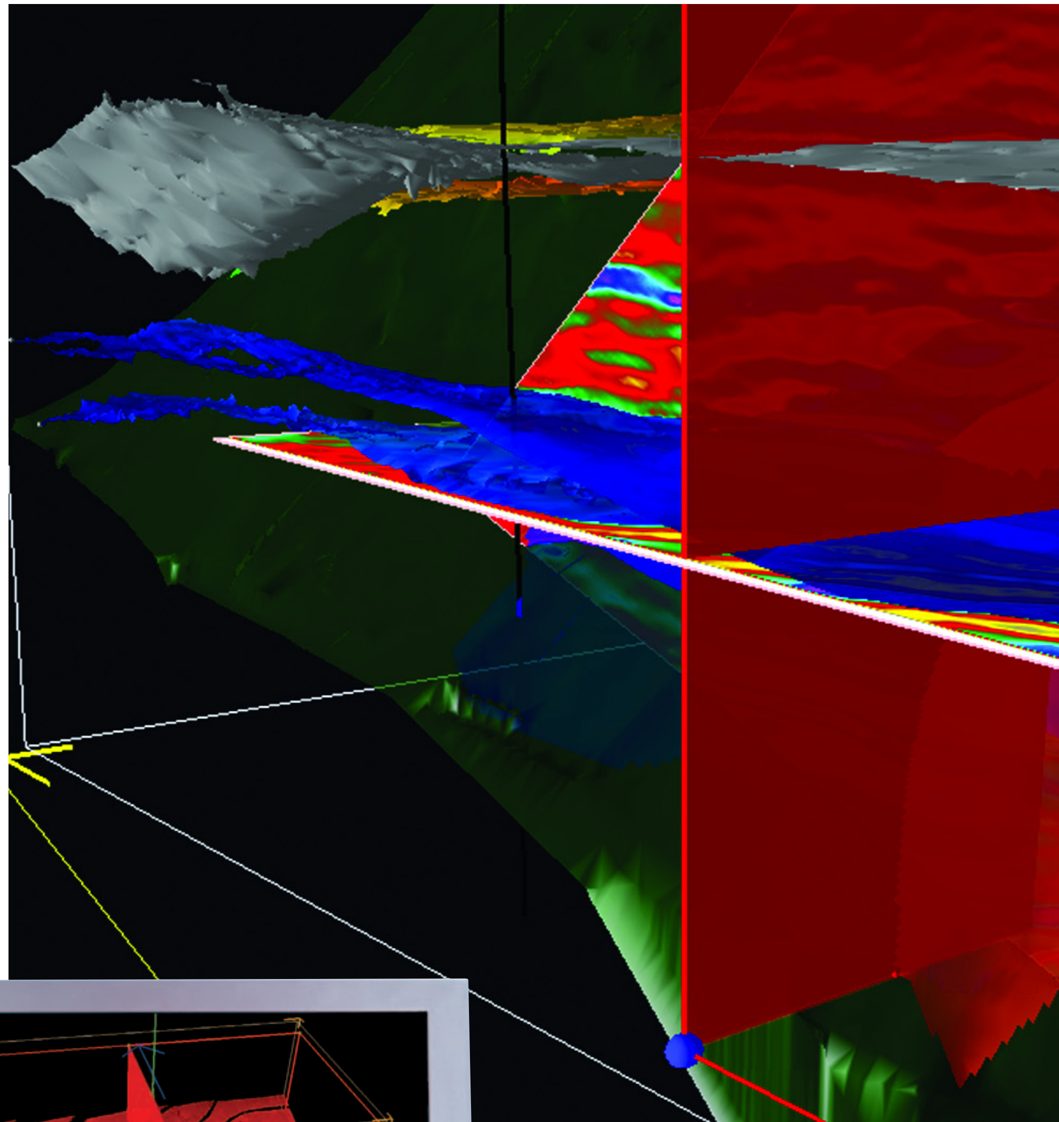


GAS CONTROLLER, *Rick Martin, in Oklahoma City, monitors transmission of natural gas on a real-time basis.*

Q ***What will be your focus as Devon's new president?***

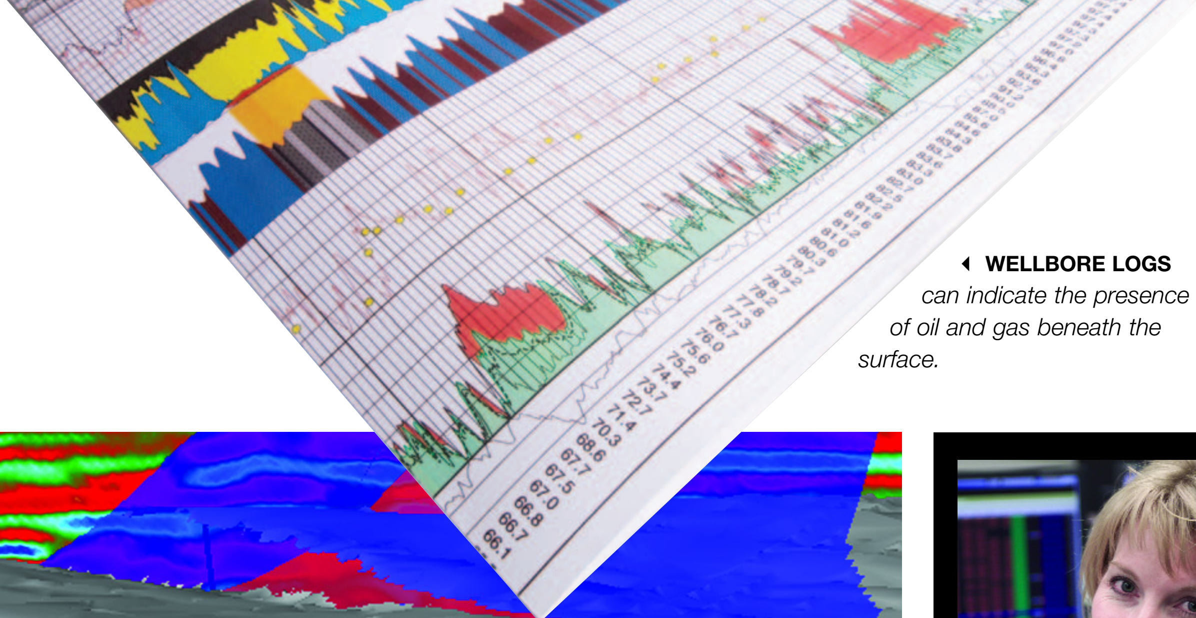
A **JOHN RICHELS:** *Continuous improvement is a top priority. We know that to be competitive and to perform at the highest levels, we can never accept the status quo. As president, I will work to communicate the importance of this to every Devon employee. Growth alone is not an objective. Building shareholder value is our overarching goal. For Devon to continue to excel, every employee must know how their efforts to be more productive contribute to achieving this goal.*

Improving technology is one dimension of continuous improvement. As managers, we can enable productivity gains by making the latest and best technologies available to all our employees. This requires a willingness to invest capital, but it also requires a willingness to encourage innovative thinking. One of my challenges is to assure that those conditions are met.

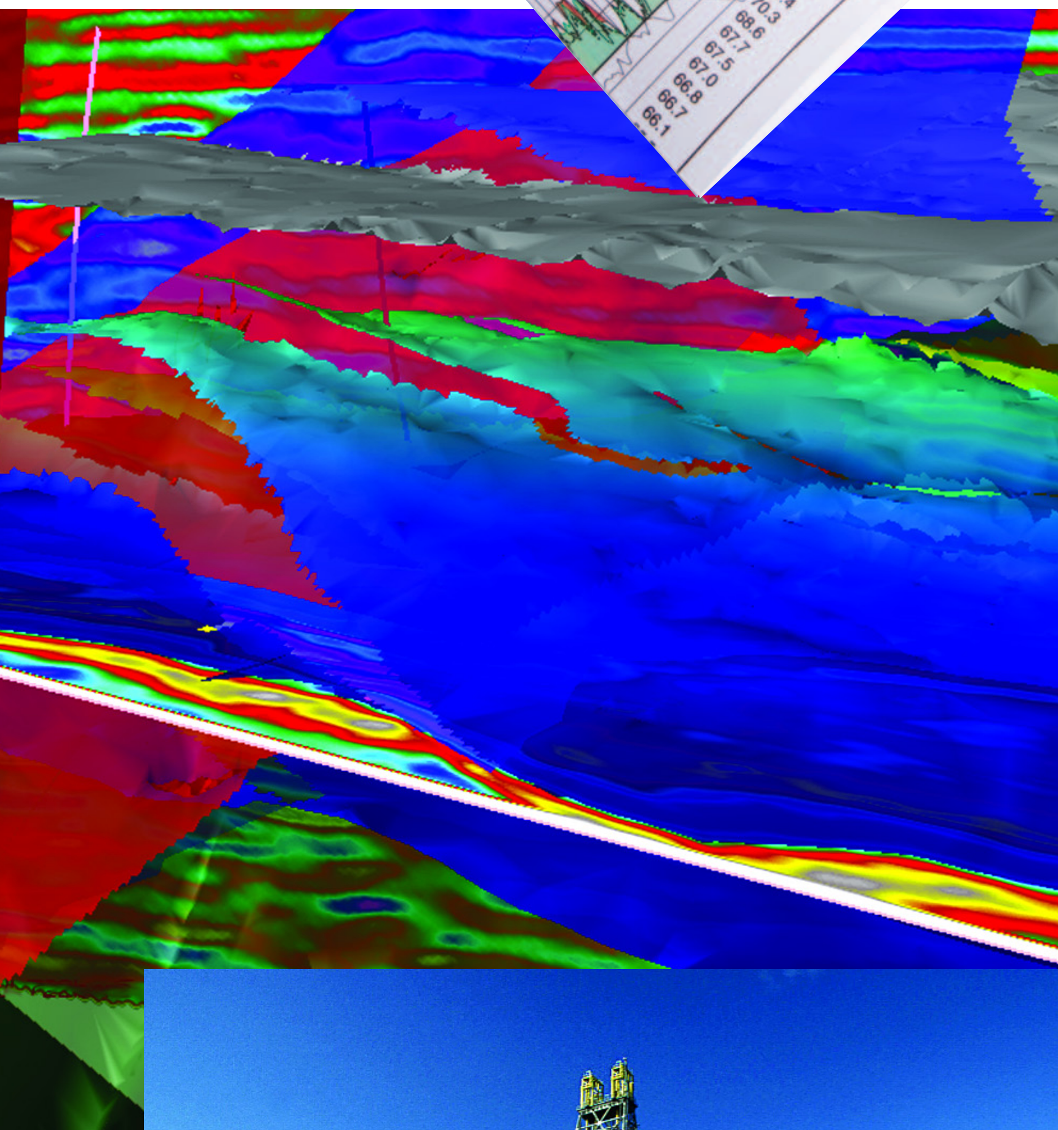


THREE-DIMENSIONAL *seismic imaging is an invaluable tool for Devon's explorationists. Devon is utilizing the latest 3-D data acquisition and processing technologies to see clearer and deeper.*

COMPUTER WORKSTATIONS *bring 3-D imaging right to the explorationist's desktop.*



WELLBORE LOGS *can indicate the presence of oil and gas beneath the surface.*



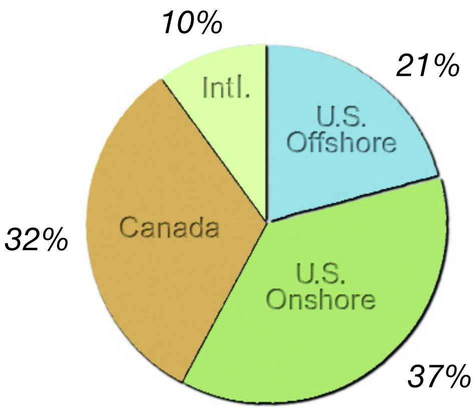
Cathy Pocock, senior Gas Sales representative in the Natural Gas Sales Department in Oklahoma City, joined Devon in September 2003.

She is responsible for marketing Devon's gas production from areas including the Rocky Mountains, San Juan Basin and Permian Basin.

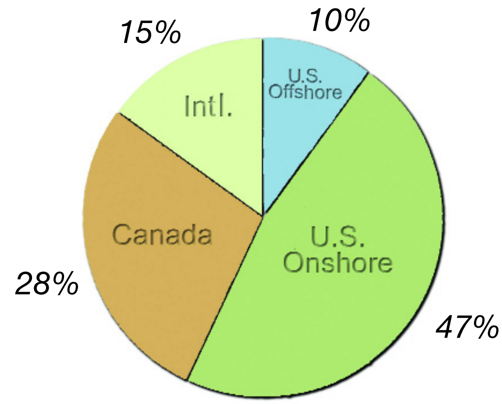
Cathy appreciates Devon's investment in technology. She says, "Immediate electronic access to multiple markets enables us to keep Devon's oil and gas flowing while maximizing our revenues."

THE TRANSOCEAN DISCOVERER SPIRIT *drills Devon's 2003 St. Malo discovery in the Gulf of Mexico. Drillships are generally deployed in water depths greater than 5,000 feet.*

Devon's 2004 Exploration, Development and Facilities Budget is $2.1 - $2.5 Billion



Devon's Proved Oil and Gas Reserves at December 31, 2003, Totaled 2.1 Billion Equivalent Barrels



Operating Statistics by Area

	PERMIAN	MID-CONTINENT(1)	ROCKY MOUNTAINS	GULF COAST(1)	U.S. OFFSHORE	TOTAL U.S.	CANADA	INTERNATIONAL	TOTAL COMPANY
Producing Wells at Year-End	9,585	5,252	5,243	4,315	1,318	25,713	6,803	511	33,027
2003 Production (Net of royalties)									
Oil (MMBbls)	9	1	2	2	17	31	14	17	62
Gas (Bcf)	56	179	107	121	126	589	267	7	863
NGLs (MMBbls)	2	11	1	2	1	17	5	-	22
Total (MMBoe) (2)	21	41	21	24	39	146	63	19	228
Average Prices									
Oil price ($/Bbl)	$ 29.39	25.11	21.33	29.95	27.23	27.64	23.54	23.64	25.63
Gas price ($/Mcf)	$ 4.65	4.22	3.82	5.13	4.78	4.50	4.57	3.47	4.51
NGLs price ($/Bbl)	$ 18.63	15.92	9.73	22.05	23.42	17.31	23.08	21.45	18.65
Oil equivalent price ($/Boe) (2)	$ 27.62	22.91	22.29	29.99	27.91	26.02	26.25	23.45	25.88
Year-End Reserves (Net of royalties)									
Oil (MMBbls)	92	4	21	14	81	212	148	301	661
Gas (Bcf)	351	1,707	1,021	1,103	702	4,884	2,297	135	7,316
NGLs (MMBbls)	17	102	8	29	5	161	48	-	209
Total (MMBoe) (2)	167	390	200	227	203	1,187	579	323	2,089
Year-End Present Value of Reserves (Millions) (3)									
Before income tax	$ 1,825	3,481	2,128	2,506	3,405	13,345	5,930	3,377	22,652
After income tax	$					9,503	4,123	2,295	15,921
Year-End Leasehold (Net acres in thousands)									
Producing	330	677	499	641	473	2,620	2,335	323	5,278
Undeveloped	506	405	885	538	1,548	3,882	9,935	12,051	25,868
Wells Drilled During 2003	308	428	366	167	56	1,325	850	54	2,229
2003 Exploration, Development and Facilities Expenditures (Millions) (4)	$ 129	398	135	232	688	1,582	741	331	2,654
Estimated 2004 Exploration, Development & Facilities Expenditures (Millions) (5)	$105-135	305-365	105-135	255-310	460-505	1,230-1,450	690-830	220-260	2,140-2,540

(1) Properties in east Texas and north Louisiana, previously included in the Mid-Continent area, are now included in the Gulf Coast area.
(2) Gas converted to oil at the ratio of 6Mcf:1Bbl. Natural gas liquids converted to oil at the ratio of 1Bbl:1Bbl.
(3) 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*.
(4) Excludes $53 million spent on marketing and midstream assets and non-cash asset retirement costs.
(5) Excludes $90 to $100 million expected to be spent on marketing and midstream assets.

Committed to Strong Corporate Governance

Trust in corporate business has been tested in recent years. Too many examples of unethical, and in some cases illegal, behavior led to a decline in investor confidence. Although we firmly believe the offenders represent a small minority, we also recognize the importance of restoring the public's trust. Devon has taken steps to emphasize our commitment to maintain a culture of the highest ethical and professional standards with sound corporate governance. These actions, however, required no material changes to our long-held beliefs and established business practices. We simply documented and formalized Devon's corporate controls and procedures that have been in place throughout our history.

In November 2003, the board of directors formally adopted Devon's *Corporate Governance Guidelines.*

Guidelines for Governance

The Nominating and Governance Committee of Devon's board of directors developed and recommended guidelines for the board. In November 2003, the board of directors formally adopted Devon's *Corporate Governance Guidelines.* These guidelines provide a framework for monitoring the effectiveness of the board and its committees as they oversee achievement of Devon's objectives. Central to those objectives is long-term enhancement of shareholder value while taking into account the interests of all Devon's stakeholders. The guidelines address the qualifications and responsibilities of directors, as well as procedures and policies relevant to carrying out the board's responsibilities.

In addition to overseeing corporate governance, the Nominating and Governance Committee of Devon's board of directors is also responsible for recruiting, recommending and nominating directors to the board. We encourage shareholders to review Devon's *Corporate Governance Guidelines* and the *Nominating and Governance Committee Charter* on our website at www.devonenergy.com.

Our Code of Conduct

Also available for review on our website is Devon's *Code of Business Conduct and Ethics*. This code applies to each of the company's directors, officers and employees. Supplementing the code, Devon has adopted numerous policies addressing specific elements of business ethics and required conduct. The code and policies encompass critical aspects of corporate behavior including protection of confidential information, trading in Devon's securities, accounting practices, conflicts of interest, receipt of gifts and abuse of drugs and alcohol. Acknowledgement of the code and compliance with its provisions are conditions of employment at Devon.

The code also addresses the importance of full and open disclosure of financial and non-financial information. In that regard, Devon has established a Disclosure Committee responsible for disclosure practices. Devon's Disclosure Committee plays a vital role in assuring that the company is in full compliance with the reporting and executive certification requirements of The Sarbanes-Oxley Act of 2002.

Role of the Audit Committee

In addition to its emphasis on financial reporting, Sarbanes-Oxley imposed responsibilities on the Audit Committee of the board of directors. These responsibilities include selection, appointment, compensation and evaluation of the company's independent auditors. The Audit Committee also reviews significant accounting principles and policies, the adequacy of internal controls and has oversight of the integrity of the company's financial statements and reporting system.

All members of the Audit Committee must be independent directors, as defined by the Securities and Exchange Commission, and one member must be a financial expert. Shareholders are encouraged to review the *Audit Committee Charter*, which is also available on Devon's website. ■

Key Property Highlights

Permian

A Southeast New Mexico

Profile
- 65% average working interest in 574,000 acres in southeast New Mexico.
- Key fields include Indian Basin, Ingle Wells and West Red Lake.
- Produces oil and gas from multiple formations at 1,500' to 12,500'.
- 57.9 million barrels of oil equivalent reserves at 12/31/03.

2003 Activity
- Drilled and completed 33 gas wells.
- Drilled and completed 40 oil wells.
- Recompleted 21 wells.

2004 Plans
- Drill 25 gas wells.
- Drill 60 oil wells.
- Evaluate recompletion opportunities.

B West Texas

Profile
- 40% average working interest in 1.1 million acres in west Texas.
- Key fields include Ozona, Reeves, Anton-Irish and Wasson.
- Produces oil and gas from multiple formations at 2,500' to 18,000'.
- 109.3 million barrels of oil equivalent reserves at 12/31/03.

2003 Activity
- Drilled and completed 12 gas wells.
- Drilled and completed 27 oil wells.
- Recompleted 17 wells.

2004 Plans
- Drill 21 gas wells.
- Drill 37 oil wells.
- Recomplete 17 wells.

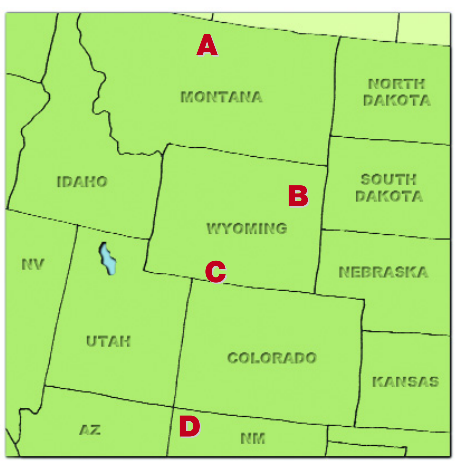
Mid-Continent

A Barnett Shale

Profile
- 550,000 net acres (120,000 within core area) in the Fort Worth Basin of north Texas.
- 95% average working interest in core.
- 80% average working interest outside core.
- Initial position obtained in 2002 merger.
- Produces gas from the Barnett Shale formation at 6,500' to 8,500'.
- 297.4 million barrels of oil equivalent reserves at 12/31/03.

2003 Activity
- Drilled 359 wells within core area, including:
  325 vertical infill wells.
  34 horizontal wells.
- Drilled 18 horizontal wells outside core area.
- Refractured 66 wells.
- Acquired 3-D seismic and acreage.

2004 Plans
- Drill 163 wells within core area, including:
  113 vertical infill wells.
  50 horizontal wells.
- Drill 60 horizontal wells outside core area.
- Refracture 34 wells.
- Acquire additional 3-D seismic and acreage.



Rocky Mountains

A Bear Paw

Profile
- 70% average working interest in 700,000 acres in north central Montana.
- Obtained in 2003 merger.
- Produces gas from the Eagle formation at 800' to 2,000'.
- 25.5 million barrels of oil equivalent reserves at 12/31/03.

2003 Activity
- Drilled and completed 97 wells.
- Acquired 2-D and 3-D seismic.

2004 Plans
- Drill 75 wells.
- Evaluate seismic for additional drilling opportunities.

B Powder River Coalbed Natural Gas

Profile
- 73% average working interest in 350,000 acres in northeastern Wyoming.
- Initial position obtained in 1992 acquisition.
- Produces coalbed natural gas from the Fort Union Coal formations at 300' to 2,000'.
- 14.8 million barrels of oil equivalent reserves at 12/31/03.

2003 Activity
- Drilled 86 coalbed gas wells.
- Connected 10 well Big George pilot to sales at Juniper Draw.
- Assumed operatorship of Rough Draw field.

2004 Plans
- Drill 110 coalbed gas wells, including 85 deep Wyodak and Big George wells.
- Recomplete approximately 50 coal wells.
- Install compression at 26 central delivery points.

C Washakie

Profile
- 76% average working interest in 211,000 acres in southern Wyoming.
- Obtained in 2000 merger.
- Produces gas from multiple formations at 6,800' to 10,300'.
- 77.0 million barrels of oil equivalent reserves at 12/31/03.

2003 Activity
- Drilled and completed 62 gas wells.
- Recompleted 10 gas wells.

2004 Plans
- Drill up to 89 gas wells.
- Recomplete 12 gas wells.

D NEBU/32-9 Units

Profile
- 25% average working interest in 50,000 acres in the San Juan Basin of northwestern New Mexico.
- Coalbed natural gas development began in the late 1980s and early 1990s.
- Includes 185 coalbed gas wells, 141 conventional wells, gas and water gathering systems and an automated production control system.
- Produces primarily coalbed gas from the Fruitland Coal formation at 3,000'.
- 23.6 million barrels of oil equivalent reserves at 12/31/03.

2003 Activity
- Received downspacing approval on all acreage.
- Drilled and completed 20 infill coalbed gas wells.
- Recavitated 7 coal wells.
- Installed 3 pumping units for water removal.
- Drilled and completed 22 conventional gas wells.
- Recompleted 3 conventional wells.

2004 Plans
- Drill up to 55 infill coalbed gas wells.
- Recavitate 5 to 10 coal wells.
- Drill 21 conventional gas wells.
- Recomplete 16 conventional wells.

Gulf Coast

A Carthage/Bethany Area

Profile
- 85% average working interest in 140,000 acres in east Texas.
- Initial position obtained in 1999 merger.
- Produces from the Cotton Valley, Travis Peak and Pettit formations at 5,700' to 9,600'.
- Includes 974 producing wells.
- 89.9 million barrels of oil equivalent reserves at 12/31/03.

2003 Activity
- Drilled and completed 38 wells.
- Recompleted 29 wells.

2004 Plans
- Complete 7 wells carried over from 2003.
- Drill 43 wells.
- Recomplete 50 wells.
- Acquire additional working interest in key areas.

B Groesbeck Area

Profile
- 74% average working interest in 154,000 acres in east central Texas.
- Added acreage in 2002 merger.
- Produces from the Cotton Valley, Travis Peak and Bossier formations at 6,000' to 13,000'.
- Includes 494 producing wells.
- 46.3 million barrels of oil equivalent reserves at 12/31/03.

2003 Activity
- Drilled and completed 35 wells.
- Recompleted 26 wells.

2004 Plans
- Complete 5 wells carried over from 2003.
- Drill up to 50 wells.
- Recomplete 54 wells.

C South Texas

Profile
- 66% average working interest in 660,000 acres.
- Initial position obtained in 1999 merger.
- Key areas include Zapata, Agua Dulce/N. Brayton, Houston and Pettus/Ray Ranch.
- Produces oil and gas from the Frio/Vicksburg, Yegua, Wilcox and Woodbine trends at 1,500' to 15,000'.
- 41.1 million barrels of oil equivalent reserves at 12/31/03.

2003 Activity
- Drilled and completed 81 wells.
- Recompleted 74 wells.
- Acquired 3-D seismic.

2004 Plans
- Drill 71 wells.
- Recomplete 117 wells.

Gulf Offshore - Shelf

A Grays Area

Profile
- Includes 100% working interest in 1 well in Galveston 424 and 65% working interest in 2 wells in Galveston 389 and 424.
- Obtained in 2000 lease sale.
- Located offshore Texas in 100' of water.

2003 Activity
- Drilled Grays discovery well.
- Drilled 2 additional wells.
- Initiated construction of production facilities.

2004 Plans
- Complete construction and installation of production facilities and pipeline.
- Commence production from 3 wells.

B Eugene Island 126 Area

Profile
- Includes 12 blocks located in and around Eugene Island 126.
- Working interests range from 25% to 100%.
- Obtained in 2003 merger.
- Located offshore Louisiana in 50' of water.
- Produces oil and gas from sands at 2,500' to 19,000'.
- 7.5 million barrels of oil equivalent reserves at 12/31/03.

2003 Activity
- Drilled and completed 4 wells at Eugene Island 126.
- Performed 7 well recompletion program in three fields: Eugene Island 100, 108 and 126.

2004 Plans
- Drill 3 wells.

C Main Pass 69 Field

Profile
- Includes 5 blocks located in and around Main Pass 69.
- 100% working interest.
- Obtained in 2003 merger.
- Located offshore Louisiana in 50' of water.
- Produces oil and gas from sands at 3,000' to 12,000'.
- 10.9 million barrels of oil equivalent reserves at 12/31/03.

2003 Activity
- Drilled and completed 3 wells at Main Pass 69.
- Reviewed seismic for potential exploration well.

2004 Plans
- Drill 1 exploration well at Main Pass 73.

Shelf Exploration Prospects

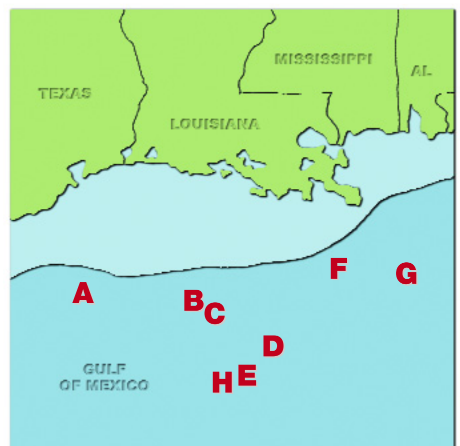
Profile

D TIKAL
- Eugene Island 142, located offshore Louisiana in 45' of water.
- Target formation: mid-Miocene sands at 17,000' to 19,000'.
- 30% working interest.
- Deep shelf prospect.
- Net unrisked reserve potential: 3 million barrels of oil equivalent.
- Apparent 2004 discovery.

E MAMBA
- West Cameron 537, located offshore Louisiana in 175' of water.
- Target formation: Miocene sands at 13,000'.
- 50% working interest.
- Net unrisked reserve potential: 7 million barrels of oil equivalent.

F TITAN
- Eugene Island 316, located offshore Louisiana in 230' of water.
- Target formation: lower Pliocene/upper Miocene sands at 15,500' to 16,000'.
- 100% working interest.
- Deep shelf prospect.
- Net unrisked reserve potential: 25 million barrels of oil equivalent.

2004 Plans
- Finalize geophysical analysis and drilling contracts.
- Bring in industry partners.
- Drill exploratory test wells.



Gulf Offshore - Deepwater

A Nansen/Boomvang Complex

Profile
- Includes 18 blocks in central East Breaks Area.
- 50% working interest at the Nansen facility.
- 20% working interest at the Boomvang facility.
- Obtained in 2003 merger.
- 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 spars.
- 66.8 million barrels of oil equivalent reserves at 12/31/03.

2003 Activity
- Drilled and completed 2 wells at Nansen.
- Installed pipeline compressor at Nansen.
- Drilled and completed 4 wells at Boomvang.
- Initiated installation of pipeline compressor at Boomvang.

2004 Plans
- Initiate production from 4 discovery wells drilled in 2003 at Boomvang.
- Complete installation of pipeline compressor at Boomvang.

B Magnolia

Profile
- 25% working interest in Garden Banks 783 and 784.
- Obtained in 2003 merger.
- Located offshore Louisiana in 4,600' of water.
- Developing 1999 discovery.
- To produce oil and gas from sands at 12,000' to 17,000'.
- 21.0 million barrels of oil equivalent reserves at 12/31/03.

2003 Activity
- Drilled 6 wells.
- Completed hull construction in Korea and transported to U.S. gulf coast.
- Continued construction of topside.

2004 Plans
- Finish construction and installation of the tension-leg platform.
- Commence production from 2 wells.

C Red Hawk

Profile
- 50% working interest in Garden Banks 876, 877, 920 and 921.
- Obtained in 2003 merger.
- Located offshore Louisiana in 5,300' of water.
- Developing 2001 discovery.
- To produce gas from sands at 16,000' to 18,500'.
- Utilizing the world's first cell spar.
- 9.7 million barrels of oil equivalent reserves at 12/31/03.

2003 Activity
- Drilled and completed 2 wells.
- Continued construction of cell spar hull and topside.

2004 Plans
- Finish construction and installation of cell spar.
- Commence production from 2 gas wells.

D Cascade

Profile
- 25% working interest in Walker Ridge 206.
- Located offshore Louisiana in 8,200' of water.
- Lower Tertiary discovery well drilled in 2002.

2003 Activity
- Finalized appraisal well location with partners.
- Initiated study of development options.
- Continued geophysical analysis.

2004 Plans
- Drill appraisal well.
- Continue evaluation of development options.

E St. Malo

Profile
- 22.5% working interest in Walker Ridge 678.
- Located offshore Louisiana in 6,900' of water.

2003 Activity
- Drilled discovery well in lower Tertiary formation.

2004 Plans
- Finalize appraisal well location.
- Drill appraisal well.
- Initiate study of development options.

F Sturgis

Profile
- 25% working interest in Atwater Valley 182.
- Located offshore Louisiana in 3,700' of water.

2003 Activity
- Drilled discovery well in lower Miocene formation.

2004 Plans
- Finalize appraisal well location.
- Drill appraisal well.

G Merganser/Vortex

Profile
- 50% working interest in Merganser, Atwater Valley 36 and 37.
- 33.3% working interest in Vortex, Atwater Valley 217 and 261.
- Obtained in 2003 merger.
- Located offshore Louisiana in 8,100' of water.
- Middle Miocene discovery wells drilled in 2001 at Merganser and 2002 at Vortex.

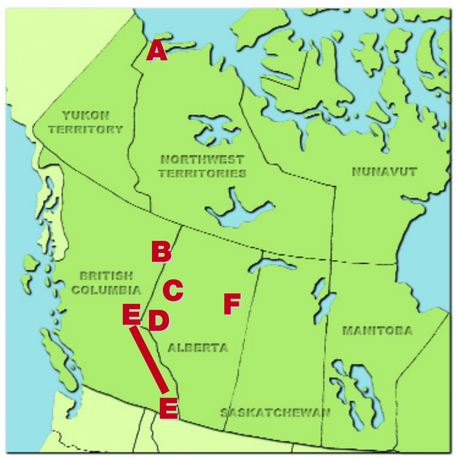
2003 Activity
- Studied development options.
- Joined with partners in other nearby discoveries to consider central hub.

2004 Plans
- Finalize development plan.
- Sanction project.

H Jack Prospect

Profile
- 25% working interest in Walker Ridge 759.
- Located offshore Louisiana in 7,100' of water.
- Target formation: lower Tertiary sands at 26,000' to 28,000'.

2004 Plans
- Finalize technical evaluation.
- Drill exploratory test well.



Canada

A Mackenzie Delta/Beaufort Sea

Profile
- 48% average working interest in 3.1 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.
- Obtained in 2001 acquisition.
- Drilling limited to winter only.
- 2002 Tuk M-18 discovery estimated at 200-300 billion cubic feet gross.

2003 Activity
- Drilled 1 exploratory dry hole.
- Suspended drilling on 1 exploratory well due to spring thaw.

2004 Plans
- Pursue farm-out opportunities on Beaufort Sea license.
- Monitor Mackenzie Valley pipeline developments.

B Northeast British Columbia

Profile
- 74% average working interest in 2.3 million acres in northwestern Alberta and northeastern British Columbia.
- Initial position obtained in 1998 merger.
- Key areas include Hamburg, Tooga/Peggo, Wildmint, Tommy Lakes and Wargen.
- Primarily winter-only drilling.
- Produces oil and gas from multiple formations including liquids-rich gas from the Slave Point at 8,000' to 10,000'.
- 75.7 million barrels of oil equivalent reserves at 12/31/03.

2003 Activity
- Completed 79 of 91 wells drilled, including:
  - 27 wells at Ring Border.
  - 6 wells at Chinchaga.
  - 6 wells at Tommy Lakes.
- Significant Slave Point discoveries at Hamburg, Chinchaga and Milligan.

2004 Plans
- Drill 98 total wells, including:
  - 25 wells at Ring Border.
  - 16 wells at Tooga/Peggo.
  - 6 wells at Chinchaga.

C Peace River Arch

Profile
- 70% average working interest in 1.3 million acres in western Alberta.
- Added acreage in 2001 acquisition.
- Key areas include Dunvegan, Dreau, Eaglesham, Pouce Coupe and Valhalla.
- Produces liquids-rich gas and light gravity oil from multiple formations at 4,500' to 8,000'.
- 94.2 million barrels of oil equivalent reserves at 12/31/03.

2003 Activity
- Completed 76 of 86 wells drilled, including:
  - 16 wells at Dunvegan.
  - 12 wells at Progress.

2004 Plans
- Drill 120 total wells (84 gas, 36 oil), including:
  - 34 gas wells at Dunvegan.
  - 10 oil wells at Progress.

D Deep Basin

Profile
- 48% average working interest in 1.6 million acres in western Alberta.
- Operate 72% of company production.
- Obtained in 2001 acquisition.
- Key areas include Wapiti, Elmworth, Bilbo, Leland and Hiding.
- Produces liquids-rich gas from primarily Cretaceous formations at 3,000' to 13,500'.
- 79.1 million barrels of oil equivalent reserves at 12/31/03.

2003 Activity
- Completed 180 of 183 wells drilled, including:
  - 61 wells at Elmworth.
  - 35 wells at Wapiti.
  - 32 wells at Bilbo.
- Expanded production facilities at Elmworth and Leland.

2004 Plans
- Drill 193 total wells, including:
  - 66 wells at Elmworth.
  - 53 wells at Wapiti.
  - 21 wells at Bilbo.
  - 12 wells at Leland.
- Continue production facilities expansion at Leland.

E Foothills

Profile
- 53% average working interest in 1.2 million acres in western Alberta and eastern British Columbia.
- Initial position obtained in 1998 merger.
- Key exploratory areas include Grizzly Valley in eastern British Columbia, Narraway, Cabin Creek and Findley in west central Alberta and Bighorn and Moose in southern Alberta.
- High impact, long-lived reserves.
- Produces gas from multiple formations at 4,000' to 15,000'.
- 85.4 million barrels of oil equivalent reserves at 12/31/03.

2003 Activity
- Completed 27 of 30 gas wells drilled, including:
  - 7 wells at Findley.
  - 5 wells at Lynx.
  - 2 wells at Bighorn.
- Increased Grizzly Valley production from 10 to 30 MMcfd as a result of pipeline expansion.
- Installed additional compression at Narraway, Findley and Lynx.

2004 Plans
- Drill 39 total wells, including:
  - 20 wells st Narraway, Lynx and Findley.
  - 10 wells at Grizzly Valley, Bighorn and Moose.

F Thermal Heavy Oil

Profile
- 44% average working interest in 340,000 acres in eastern Alberta oil sands.
- Initial position obtained in 1998 merger.
- Key areas include Jackfish (100% interest), Dover (92% interest) and Surmont (13% interest).
- Steam-Assisted Gravity Drainage (SAGD) is the principle recovery method.
- 300 million barrel potential at Jackfish.

2003 Activity
- Launched $400 million Jackfish SAGD project.
- Requested regulatory approval for 35,000 barrel per day Jackfish project.
- Drilled 153 stratigraphic wells at Dover, Jackfish and Surmont.
- Surmont SAGD project launched.

2004 Plans
- Proceed with regulatory approval and engineering design at Jackfish.
- Acquire additional acreage and seismic at Jackfish.

International

A Azerbaijan - ACG

Profile
- 5.6% carried interest in 137,000 acres in the Azeri-Chirag-Gunashli (ACG) oil fields offshore Azerbaijan.
- Operating and capital cost currently paid by partners under carried interest agreement.
- Initial position obtained in 1999 merger.
- Major oil export pipeline to be completed in 2005.
- Expect in excess of 50,000 barrels per day net to Devon beginning in 2008 - 2009.
- 129.2 million barrels of oil equivalent reserves at 12/31/03.

2003 Activity
- Drilled 1 extended reach well from the Chirag platform.
- Drilled remaining 6 wells for future production from the Central Azeri platform.

2004 Plans
- Drill 1 extended reach well from the Chirag platform.
- Convert 2 wells to injector wells.
- Install Central Azeri platform and production facilities.
- Drill 8 to 10 wells for future production from the East Azeri and West Azeri platforms.
- Sanction phase 3 field development.

B China - Panyu

Profile
- 24.5% working interest in 950,000 acres in block 15/34 offshore China.
- Located in the Pearl River Mouth Basin in 300' of water.
- Obtained in 2000 merger.
- Produces oil from 1998 and 1999 Panyu discoveries.
- 17.3 million barrels of oil equivalent reserves at 12/31/03.

2003 Activity
- Completed construction and installation of Panyu facilities.
- Completed construction and commissioned floating production, storage and offloading vessel (FPSO).
- Drilled 6 development wells at Panyu.
- Commenced production.

2004 Plans
- Drill 21 development wells at Panyu.
- Drill 1 to 2 exploratory wells in satellite fields.

C Equatorial Guinea - Zafiro

Profile
- 23.75% working interest in 35,900 acres in the Zafiro field in block B offshore Equatorial Guinea.
- Obtained in 2003 merger.
- Field facilities include one fixed production platform and 2 floating production, storage and offloading vessels (FPSO) in 500' to 2,500' of water.
- Contains 48 producing wells and 13 injector wells.
- Produces oil from a complex system of reservoir channels at 5,000' to 6,000'.
- 107.9 million barrels of oil equivalent reserves at 12/31/03.

2003 Activity
- Completed construction and commissioned the Serpentina FPSO in Southern Expansion Area (SEA).
- Completed 11 producers and 1 injector well in the SEA.
- Drilled and completed 9 additional wells elsewhere in the field.
- Commenced production from the SEA.
- Increased gross field production to record 290,000 barrels per day.

2004 Plans
- Expect to reach cost recovery payout mid-year.
- Drill 18 to 20 wells.
- Evaluate 3-D seismic for future potential.

D South Atlantic Margin Exploration

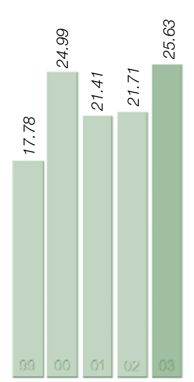
Profile
- 5.1 million net acres in 10 licensed blocks offshore West Africa:
  - Block 10 offshore Angola; 35% interest.
  - Block 16 offshore Angola; 15% interest.
  - Block 24 offshore Angola; 65% interest.
  - Agali block offshore Gabon; 50% interest.
  - Keta block offshore Ghana; 50% interest.
  - Block B offshore E.G.; 23.75% interest.
  - Block C offshore E.G.; 37.6% interest.
  - Block N offshore E.G.; 34% interest.
  - Block P offshore E.G.; 38.4% interest.
  - Block 256 offshore Nigeria; 95% interest.
- 1.1 million net acres in 5 licensed blocks offshore Brazil:
  - BC-2 block; 15% interest.
  - BM-BAR-3 block; 100% interest.
  - BM-C-8 block; 60% interest.
  - BM-C-15 block; 65% interest.
  - BM-S-22 block; 20% interest.
- Obtained positions 1999 - 2003.

2003 Activity
- Drilled 2 exploratory dry holes on blocks 16 and 24 in Angola.
- Acquired 3-D seismic on block 10 in Angola.
- Drilled 1 exploratory dry hole on the Keta block in Ghana.
- Secured farmout agreements with industry partners on block C in E.G.
- Drilled 1 exploratory dry hole on block N in E.G.
- Acquired 3-D seismic on block P in E.G.
- Acquired 3-D seismic on block 256 in Nigeria.
- Acquired 3-D seismic on block BM-BAR-3 in Brazil.
- Solicited farmout on block BM-C-8 in Brazil.

2004 Plans
- Drill 1 exploratory well on block 24 in Angola.
- Drill 1 exploratory well on block 10 in Angola.
- Drill 1 exploratory well on block B in E.G.
- Drill 1 exploratory well on block C in E.G.
- Drill 1 exploratory well on block P in E.G.
- Drill 1 exploratory well on block 256 in Nigeria.
- Drill 1 exploratory well on block BM-C-8 in Brazil.

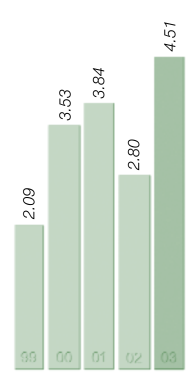
Financial Statements and Management's Discussion and Analysis

Average Oil Price Received
($ per Bbl)



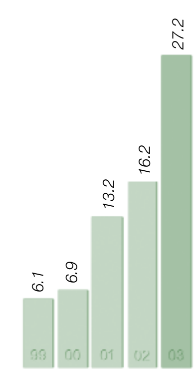
Devon's average realized oil prices increased 18% in 2003...

Average Gas Price Received
($ per Mcf)



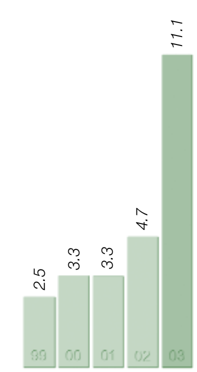
...while our average realized natural gas prices increased 61%.

Total Assets
($ Billions)



The Ocean merger and record net earnings pushed total assets to $27.2 billion...

Stockholders' Equity
($ Billions)



...and more than doubled stockholders' equity to $11.1 billion.

Selected 11-Year Financial Data (1)

		1993	1994	1995	1996
OPERATING RESULTS (In millions, except per share data)					
Revenues (Net of royalties):					
Oil sales	$	355	351	419	529
Gas sales	$	189	171	157	211
Natural gas liquids sales	$	13	13	15	29
Marketing & midstream revenues	$	—	—	—	—
Other income	$	31	14	35	36
Total revenues	$	588	549	626	805
Production and operating expenses	$	227	218	222	271
Marketing & midstream costs and expenses	$	—	—	—	—
Depreciation, depletion and amortization of property and equipment	$	170	149	160	175
Accretion of asset retirement obligation	$	—	—	—	—
Amortization of goodwill (2)	$	—	—	—	—
General and administrative expenses	$	51	45	43	57
Expenses related to mergers	$	11	7	—	—
Interest expense (3)	$	42	29	39	59
Dividends on subsidiary's preferred stock	$	—	—	—	—
Effects of changes in foreign currency exchange rates	$	—	—	—	—
Change in fair value of financial instruments	$	—	—	—	—
Reduction of carrying value of oil and gas properties	$	180	22	97	—
Impairment of ChevronTexaco common stock	$	—	—	—	—
Income tax expense (benefit)	$	(68)	25	19	106
Total expenses	$	613	495	580	668
Net earnings (loss) before minority interest, cumulative effect of change in accounting principle and discontinued operations (4)	$	(25)	54	46	137
Net earnings (loss)	$	(55)	54	55	151
Preferred stock dividends	$	7	11	15	47
Net earnings (loss) to common shareholders	$	(62)	43	40	104
Net earnings (loss) per common share:					
Basic	$	(1.27)	0.84	0.76	1.97
Diluted	$	(1.27)	0.84	0.76	1.92
Weighted average shares outstanding:					
Basic		49	51	52	53
Diluted		49	54	53	56
BALANCE SHEET DATA (In millions)					
Total assets	$	1,336	1,475	1,639	2,242
Debentures exchangeable into shares of ChevronTexaco Corporation common stock (5)	$	—	—	—	—
Other long-term debt (6)	$	508	457	565	511
Deferred income taxes	$	—	30	48	136
Stockholders' equity	$	472	688	739	1,160
Common shares outstanding		49	52	52	63

(1) All of the years shown exclude results from Devon's operations in Indonesia, Argentina and Egypt that were discontinued in 2002. Subsequent to the sale of its Egyptian and Indonesian operations, Devon acquired new Egyptian and Indonesian assets in the April 2003 Ocean merger. Amounts and activities related to these new Egyptian and Indonesian operations are included in Devon's continuing operations in 2003.

(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) Includes distributions on preferred securities of subsidiary trust of $5, $10, $10 and $7 million in 1996, 1997, 1998 and 1999, respectively.

(4) 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 ($1), $49 and $16 million in 1993, 2001 and 2003, respectively, and the results of discontinued operations of ($29), $0, $9, $15, $13, ($35), $39, $69, $31 and $45 million in 1993 through 2002, respectively.

(5) Devon beneficially owns approximately 7 million shares of ChevronTexaco Corporation common stock. These shares have been deposited with an exchange agent for possible exchange for $760 million principal amount of exchangeable debentures. The ChevronTexaco shares and debentures were acquired through the August 1999 merger with PennzEnergy.

(6) Includes preferred securities of subsidiary trust of $149 million in years 1996, 1997 and 1998.

NM Not a meaningful number.

1997	1998	1999	2000	2001	2002	2003	5-YEAR GROWTH RATE	10-YEAR GROWTH RATE
497	236	436	906	784	909	1,588	46%	16%
367	335	616	1,474	1,878	2,133	3,897	63%	35%
36	25	68	154	131	275	407	75%	41%
10	8	20	53	71	999	1,460	183%	NM
42	22	10	40	69	34	37	11%	2%
952	626	1,150	2,627	2,933	4,350	7,389	64%	29%
288	231	328	544	666	886	1,282	41%	19%
4	3	10	28	47	808	1,174	230%	NM
268	212	379	662	831	1,211	1,793	53%	27%
—	—	—	—	—	—	36	NM	NM
—	—	16	41	34	—	—	NM	NM
56	48	83	96	114	219	307	45%	20%
—	13	17	60	1	—	7	(12%)	(4%)
51	53	122	155	220	533	502	57%	28%
—	—	—	—	—	—	2	NM	NM
6	16	(13)	3	11	(1)	(69)	NM	NM
—	—	—	—	2	(28)	(1)	NM	NM
633	354	476	—	979	651	111	(21%)	(5%)
—	—	—	—	—	205	—	NM	NM
(128)	(103)	(75)	377	5	(193)	514	NM	NM
1,178	827	1,343	1,966	2,910	4,291	5,658	47%	25%
(226)	(201)	(193)	661	23	59	1,731	NM	NM
(218)	(236)	(154)	730	103	104	1,747	NM	NM
12	—	4	10	10	10	10	NM	4%
(230)	(236)	(158)	720	93	94	1,737	NM	NM
(3.35)	(3.32)	(1.68)	5.66	0.73	0.61	8.32	NM	NM
(3.35)	(3.32)	(1.68)	5.50	0.72	0.61	8.07	NM	NM
69	71	94	127	128	155	209	24%	16%
75	77	99	132	130	156	217	23%	16%
1,965	1,931	6,096	6,860	13,184	16,225	27,162	70%	35%
—	—	760	760	649	662	677	NM	NM
576	885	1,656	1,289	5,940	6,900	7,903	55%	32%
50	15	313	634	2,149	2,627	4,370	NM	NM
1,006	750	2,521	3,277	3,259	4,653	11,056	71%	37%
71	71	126	129	126	157	236	27%	17%

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

OVERVIEW

On April 25, 2003, Devon supplemented its property portfolio and improved its growth outlook when it merged with Ocean Energy. Former Ocean shareholders received 74 million new Devon common shares in exchange for their Ocean shares. The merger enhances our current production profile and provides outstanding prospects for growth. We have substantially integrated the Devon and Ocean organizations and consolidated all our Houston area employees at our downtown Houston location.

2003 was a record-breaking year for Devon. We produced 228 million Boe, the highest annual production in our history. Our marketing and midstream operations also contributed $286 million to operating margins. Total revenues for 2003 exceeded $7 billion, and led to record profits and operating cash flow. Devon delivered the highest net earnings, $1.7 billion, and earnings per diluted share, $8.07, in its 15 years as a public company.

Cash flow from operations was $3.8 billion for the year. This allowed Devon to fully fund our $2.6 billion of capital expenditures, retire over $500 million in long-term debt and add almost $1 billion to cash on hand. We are continuing to accumulate cash with the intent to repay debt as it matures in 2004 and subsequent years.

The significant increase in revenues and earnings resulted from both production growth and higher commodity prices. We increased production by 40 million Boe, or 21%, due both to the Ocean merger and the impact of Devon's exploration and development activities. On a pro forma basis, as if the merger had been completed on January 1, 2002, Devon increased production from retained properties year-over-year by 5.5%. Average oil, gas and NGL prices increased 18%, 61% and 33%, respectively from 2002 to 2003. Our current price outlook assumes that, over the next few years, oil prices will decline toward the OPEC stated price range of $22 to $28 per barrel from more than $30 per barrel today. Our outlook is that natural gas prices will remain in a range of $3 to $5 per MMBtu for the foreseeable future. Historically, the OPEC basket price has been approximately $2 per barrel less than the NYMEX price.

In addition to dramatically increasing production and revenues, the Ocean merger increased our expenses in most categories. Furthermore, higher oil, gas and NGL prices have led to upward pressure on many of Devon's expenses such as power and fuel. Higher oil and gas prices have also led to higher demand for oilfield supplies and services and have often caused increases in the costs of such goods and services. However, these same commodity price increases have also resulted in higher costs that are opportunity-driven. For example, with the increase in oil, gas and NGL prices, more well workovers and repairs and maintenance costs can be profitably performed to maintain or increase production volumes.

Additionally, the weakening of the U.S. dollar versus the Canadian dollar caused increases in all of our Canadian dollar expenses as expressed in U.S. dollars. This contributed approximately $88 million in aggregate, or $0.39 per Boe, to 2003 production and operating costs, depreciation, depletion and amortization expenses and general and administrative expenses. Based on Devon's assumption that the average Canadian-to-U.S. dollar exchange rate will increase from $0.7160 in 2003 to $0.7600 in 2004, the exchange rate effect would increase these expense categories another $58 million, or $0.23 per Boe, from 2003 to 2004.

Because oil, gas and NGL prices are influenced by many factors outside of our control, Devon's management has focused its efforts on increasing oil and gas reserves and production and controlling costs. Devon's future earnings and cash flows are dependent on our ability to continue to contain our overall cost structure at a level that will allow for profitable production.

Devon drilled almost 300 exploration wells and more than 1,900 development wells during 2003. We incurred finding and development costs, including business combinations, of $7.9 billion in 2003. Including 556 million Boe of proved reserves that were acquired, Devon replaced 321% of annual production. We closed 2003 with proved reserves of 2.1 billion Boe. This resulted in per-unit finding and development costs, including business combinations, which were higher than both Devon's historical and the industry averages. Management is focused on lowering our per-unit finding and development costs in future years.

Timing differences often occur between the years in which capital costs are incurred and the years in which related proved reserves are booked. This contributed significantly to higher per-unit finding and development costs in recent years. For example, Devon had several potential discoveries in 2003 from our exploration program. We believe our deepwater Gulf of Mexico discoveries at St. Malo and Sturgis and the 2002 Cascade and Tuk M-18 discoveries will contribute significantly to Devon's proved reserves. However, due to the long-term nature of these projects, additional testing and approval of development plans are needed before we can record the potential reserves as proved. Therefore, we have not yet recorded any reserves related to these projects, even though the costs of drilling the wells have already been included in our finding and development costs.

Another contributor to 2003 finding and development costs is related to the development of previously booked undeveloped reserves. We invested about $900 million of capital in 2003 developing reserves previously classified as proved undeveloped. Many of these reserves were associated with assets acquired in the Ocean merger and other recent acquisitions. This allowed us to reduce our percentage of reserves classified as proved undeveloped from 31% following the Ocean merger to 24% at year-end.

We expect to begin recording proved reserves within the next 12 to 18 months from some of our recent discoveries. We also expect to reduce the amount of costs incurred to develop proved undeveloped reserves. Therefore, we are optimistic that our per-unit finding and development costs will decline to more competitive levels.

During 2003, Devon marked its 15th anniversary as a public company. While we have consistently increased production over this 15-year period, volatility in oil, gas and NGL prices has resulted in considerable variability in earnings and cash flows. Prices for oil, natural gas and NGLs are determined primarily by market conditions. Market conditions for these products have been, and will continue to be, influenced by regional and worldwide economic activity, weather and other factors that are beyond Devon's control. Devon's future earnings and cash flows will continue to depend on market conditions.

Like all oil and gas exploration and production companies, Devon faces the challenge of natural production decline. As initial reservoir pressures are depleted, oil and gas production from a given well naturally decreases. Thus, an oil and gas exploration and production company depletes part of its asset base with each unit of oil or gas it produces. Historically, Devon has been able to overcome this natural decline by adding, through drilling and acquisitions, more reserves than it produces. Devon's future growth will depend on its ability to continue to add reserves in excess of production.

In summary, as we head into 2004 and beyond, we are poised to continue growing organically through both our long-term investment in high-impact exploration projects and our lower-risk development of proved undeveloped reserves. In addition, we expect to continue to strengthen our balance sheet through the accumulation of cash to meet future debt maturities.

RESULTS OF OPERATIONS

Revenues Changes in oil, gas and NGL production, prices and revenues from 2001 to 2003 are shown in the following tables. (Unless otherwise stated, all dollar amounts are expressed in U.S. dollars.)

		TOTAL YEAR ENDED DECEMBER 31,				
		2003	2003 vs 2002 (2)	2002	2002 vs 2001 (2)	2001
PRODUCTION						
Oil (MMBbls)		62	+48%	42	+17%	36
Gas (Bcf)		863	+13%	761	+56%	489
NGLs (MMBbls)		22	+11%	19	+138%	8
Oil, gas and NGLs (MMBoe) (1)		228	+21%	188	+50%	126
AVERAGE PRICES						
Oil (per Bbl)	$	25.63	+18%	21.71	+1%	21.41
Gas (per Mcf)	$	4.51	+61%	2.80	-27%	3.84
NGLs (per Bbl)	$	18.65	+33%	14.05	-17%	16.99
Oil, gas and NGLs (per Boe) (1)	$	25.88	+47%	17.61	-21%	22.19
REVENUES ($ in millions)						
Oil	$	1,588	+75%	909	+16%	784
Gas	$	3,897	+83%	2,133	+14%	1,878
NGLs	$	407	+48%	275	+110%	131
Oil, gas and NGLs	$	5,892	+78%	3,317	+19%	2,793

		DOMESTIC YEAR ENDED DECEMBER 31,				
		2003	2003 vs 2002 (2)	2002	2002 vs 2001 (2)	2001
PRODUCTION						
Oil (MMBbls)		31	+31%	24	-8%	26
Gas (Bcf)		589	+22%	482	+28%	376
NGLs (MMBbls)		17	+16%	14	+133%	6
Oil, gas and NGLs (MMBoe) (1)		146	+23%	118	+24%	95
AVERAGE PRICES						
Oil (per Bbl)	$	27.64	+26%	21.99	-2%	22.36
Gas (per Mcf)	$	4.50	+55%	2.91	-30%	4.17
NGLs (per Bbl)	$	17.31	+29%	13.37	-22%	17.15
Oil, gas and NGLs (per Boe) (1)	$	26.02	+46%	17.87	-25%	23.80
REVENUES ($ in millions)						
Oil	$	861	+64%	524	-11%	586
Gas	$	2,652	+89%	1,403	-11%	1,571
NGLs	$	289	+51%	192	+86%	103
Oil, gas and NGLs	$	3,802	+79%	2,119	-6%	2,260

				CANADA YEAR ENDED DECEMBER 31,		
		2003	2003 vs 2002 [2]	2002	2002 vs 2001 [2]	2001
PRODUCTION						
Oil (MMBbls)		14	-14%	16	+100%	8
Gas (Bcf)		267	-4%	279	+147%	113
NGLs (MMBbls)		5	-5%	5	+150%	2
Oil, gas and NGLs (MMBoe) [1]		63	-7%	68	+134%	29
AVERAGE PRICES						
Oil (per Bbl)	$	23.54	+12%	21.00	+18%	17.84
Gas (per Mcf)	$	4.57	+74%	2.62	-4%	2.73
NGLs (per Bbl)	$	23.08	+45%	15.93	-3%	16.43
Oil, gas and NGLs (per Boe) [1]	$	26.25	+55%	16.96	+1%	16.80
REVENUES ($ in millions)						
Oil	$	318	-4%	331	+127%	146
Gas	$	1,222	+67%	730	+138%	307
NGLs	$	114	+37%	83	+196%	28
Oil, gas and NGLs	$	1,654	+45%	1,144	+138%	481

				INTERNATIONAL YEAR ENDED DECEMBER 31,		
		2003	2003 vs 2002 [2]	2002	2002 vs 2001 [2]	2001
PRODUCTION						
Oil (MMBbls)		17	+662%	2	—	2
Gas (Bcf)		7	NM	—	NM	—
NGLs (MMBbls)		—	NM	—	NM	—
Oil, gas and NGLs (MMBoe) [1]		19	+719%	2	—	2
AVERAGE PRICES						
Oil (per Bbl)	$	23.64	—	23.70	+1%	23.42
Gas (per Mcf)	$	3.47	NM	—	NM	—
NGLs (per Bbl)	$	21.45	NM	—	NM	—
Oil, gas and NGLs (per Boe) [1]	$	23.45	-1%	23.70	+1%	23.42
REVENUES ($ in millions)						
Oil	$	409	+660%	54	+4%	52
Gas	$	23	NM	—	NM	—
NGLs	$	4	NM	—	NM	—
Oil, gas and NGLs	$	436	+710%	54	+4%	52

(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. The respective prices of oil, gas and NGLs are affected by market and other factors in addition to relative energy content.

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

NM Not meaningful.

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

		WITH HEDGES			WITHOUT HEDGES		
		2003	2002	2001	2003	2002	2001
Oil (per Bbl)	$	25.63	21.71	21.41	27.67	22.63	21.79
Gas (per Mcf)	$	4.51	2.80	3.84	4.79	2.70	3.89
NGLs (per Bbl)	$	18.65	14.05	16.99	18.65	14.05	16.99
Oil, gas and NGLs (per Boe)	$	25.88	17.61	22.19	27.48	17.36	22.48

Oil Revenues *2003 vs. 2002* Oil revenues increased $679 million in 2003. An increase in 2003 production of 20 million barrels caused oil revenues to increase by $436 million. The April 2003 Ocean merger accounted for 25 million barrels of increased production, partially offset by production lost from the 2002 property divestitures of 5 million barrels. Oil revenues increased $243 million due to a $3.92 increase in the average price of oil.

2002 vs. 2001 Oil revenues increased $125 million in 2002. An increase in 2002 production of 6 million barrels caused oil revenues to increase by $112 million. The 2001 Anderson acquisition and 2002 Mitchell merger accounted for 11 million barrels of increased production. This was partially offset by the effect of the 2002 property divestitures, which reduced production by 5 million barrels. A $0.30 per barrel increase in the average oil price in 2002 accounted for the remaining $13 million of increased oil revenues.

Gas Revenues *2003 vs. 2002* Gas revenues increased $1.8 billion in 2003. A $1.71 per Mcf increase in the average gas price caused revenues to increase by $1.5 billion. An increase in 2003 production of 102 Bcf caused gas revenues to increase by $287 million. The April 2003 Ocean merger and January 2002 Mitchell merger accounted for 113 Bcf and 11 Bcf of increased production, respectively, partially offset by production lost from the 2002 property divestitures of 36 Bcf. The remaining production increase was primarily related to new drilling and development in the Barnett Shale properties.

2002 vs. 2001 Gas revenues increased $255 million in 2002. An increase in production of 272 Bcf caused gas revenues to increase by $1.0 billion. The Anderson acquisition and Mitchell merger accounted for 323 Bcf of increased production. This was partially offset by the effect of the 2002 property divestitures, which reduced production by 30 Bcf, and by natural declines in production. The effects of the net production increase were partially offset by a $1.04 per Mcf decrease in the average gas price in 2002.

NGL Revenues *2003 vs. 2002* NGL revenues increased $132 million in 2003. A $4.60 per barrel increase in average NGL prices caused revenues to increase by $100 million. An increase in 2003 production of 3 million barrels caused revenues to increase $32 million. The April 2003 Ocean merger and January 2002 Mitchell merger each accounted for 1 million barrels of increased production. This was partially offset by production lost from the 2002 property divestitures of 1 million barrels. The remaining production increase was primarily related to new drilling and development in the Barnett Shale properties.

2002 vs. 2001 NGL revenues increased $144 million in 2002. An 11 million barrel increase in 2002 production caused revenues to increase $202 million. The Anderson acquisition and Mitchell merger accounted for 12 million barrels of increased production. This was partially offset by production lost from divestitures. The effects of the net production increase were partially offset by a $2.94 per barrel decrease in the average NGL price in 2002.

Marketing and Midstream Revenues *2003 vs. 2002* Marketing and midstream revenues increased $461 million in 2003. Of this increase, approximately $439 million was the result of an increase in gas and NGL prices. An increase in third-party processed NGL volumes caused the remaining increase in 2003 revenues. The increase in volumes was primarily related to new drilling and development in the Barnett Shale properties and an additional 24 days of production in 2003 due to the timing of the January 2002 Mitchell merger. This was partially offset by volumes lost as a result of processing plant dispositions.

2002 vs. 2001 Marketing and midstream revenues increased $928 million in 2002. The Mitchell merger included significant marketing and midstream assets which accounted for substantially all of the increase in revenues.

Operating Costs and Expenses The details of the changes in operating costs and expenses between 2001 and 2003 are shown in the table below.

		YEAR ENDED DECEMBER 31,			
	2003	2003 vs 2002 (2)	2002	2002 vs 2001(2)	2001
Operating Costs and Expenses ($ in millions):					
Production and operating expenses:					
Lease operating expenses	$ 871	+40%	621	+33%	467
Transportation costs	207	+34%	154	+86%	83
Production taxes	204	+84%	111	-4%	116
Total production and operating expenses	1,282	+45%	886	+33%	666
Depreciation, depletion and amortization of oil and gas properties	1,668	+51%	1,106	+39%	793
Accretion of asset retirement obligation	36	NM	—	NM	—
Amortization of goodwill	—	NM	—	-100%	34
Subtotal	2,986	+50%	1,992	+33%	1,493
Marketing and midstream operating costs and expenses	1,174	+45%	808	+1,619%	47
Depreciation and amortization of non-oil and gas properties	125	+19%	105	+176%	38
General and administrative expenses	307	+40%	219	+92%	114
Expenses related to mergers	7	NM	—	-100%	1
Reduction of carrying value of oil and gas properties	111	-83%	651	-34%	979
Total	$ 4,710	+25%	3,775	+41%	2,672
Operating Costs and Expenses per Boe:					
Production and operating expenses:					
Lease operating expenses	$ 3.82	+16%	3.30	-11%	3.71
Transportation costs	0.91	+11%	0.82	+24%	0.66
Production taxes	0.90	+53%	0.59	-36%	0.92
Total production and operating expenses	5.63	+20%	4.71	-11%	5.29
Depreciation, depletion and amortization of oil and gas properties	7.33	+25%	5.88	-7%	6.30
Accretion of asset retirement obligation	0.16	NM	—	NM	—
Amortization of goodwill	—	NM	—	-100%	0.27
Subtotal	13.12	+24%	10.59	-11%	11.86
Marketing and midstream operating costs and expenses (1)	5.15	+20%	4.29	+1,059%	0.37
Depreciation and amortization of non-oil and gas properties (1)	0.55	—	0.55	+83%	0.30
General and administrative expenses (1)	1.35	+16%	1.16	+27%	0.91
Expenses related to mergers (1)	0.03	NM	—	-100%	0.01
Reduction of carrying value of oil and gas properties (1)	0.49	-86%	3.45	-56%	7.78
Total	$ 20.69	+3%	20.04	-6%	21.23

(1) Though per Boe amounts for these expense items may be helpful for profitability trend analysis, these expenses are not directly attributable to production volumes.
(2) All percentage changes included in this table are based on actual figures and not the rounded figures included in this table.
NM Not meaningful.

Oil, Gas and NGLs Production and Operating Expenses *2003 vs. 2002* Lease operating expenses increased $250 million in 2003. The April 2003 Ocean merger accounted for $168 million of the increase. Lease operating expenses on our historical properties increased $105 million, due to an increase in well workover expenses and increased power, fuel, casualty insurance and repairs and maintenance costs. Additionally, changes in the Canadian-to-U.S. dollar exchange rate resulted in a $37 million increase in costs. These increases were partially offset by a decrease of $60 million due to the 2002 property divestitures.

The increase in lease operating expenses per Boe is primarily related to greater well workover expenses and increased power, fuel and repairs and maintenance costs. Changes in the Canadian-to-U.S. dollar exchange rate also contributed to the increase. Because of higher oil, gas and NGL prices, more well workovers and repairs and maintenance costs are performed to either maintain or improve production volumes. These higher prices also resulted in increased power and fuel costs.

Transportation costs represent those costs paid directly to third-party providers to transport oil, gas and NGL production sold downstream from the wellhead. Devon's transportation costs increased $53 million in 2003. The April 2003 Ocean merger accounted for $31 million of the increase and $7 million was related to changes in the Canadian-to-U.S. dollar exchange rate. The remainder of the increase was due primarily to an increase in gas production.

Production taxes increased $93 million in 2003. The majority of Devon's 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 79% increase in domestic oil, gas and NGLs revenues was the primary cause of the production tax increase.

2002 vs. 2001 Lease operating expenses increased $154 million in 2002. The Anderson acquisition and Mitchell merger accounted for $210 million of the increase. The historical Devon lease operating expenses decreased $56 million primarily due to divestitures. The drop in lease operating expenses per Boe from $3.71 in 2001 to $3.30 in 2002 was primarily related to the lower cost properties acquired in the Anderson acquisition and Mitchell merger. We also divested some higher cost properties in 2002.

Transportation costs increased $71 million in 2002 primarily due to an increase in gas production from the Anderson acquisition and Mitchell merger.

As stated previously, most U.S. production taxes are based on a fixed percentage of revenues. Therefore, the 6% decrease in domestic oil, gas and NGLs revenues was the primary cause of the production tax decrease.

Depreciation, Depletion and Amortization of Oil and Gas Properties ("DD&A") DD&A of oil and gas properties is calculated as the percentage of total proved reserve volumes produced during the year, multiplied by the net capitalized investment plus future development costs in those reserves (the "depletable base"). 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.

2003 vs. 2002 Oil and gas property related DD&A increased $562 million in 2003. An increase in the combined U.S., Canadian and international DD&A rate from $5.88 per BOE in 2002 to $7.33 per BOE in 2003 caused oil and gas property related DD&A to increase by $331 million. The increase in the DD&A rate is primarily related to the April 2003 Ocean merger, higher finding and development costs and changes in the Canadian-to-U.S. dollar exchange rate. A 21% increase in 2003 oil, gas and NGLs production caused DD&A to increase $231 million.

2002 vs. 2001 Oil and gas property related DD&A increased $313 million in 2002. A 50% increase in 2002 oil, gas and NGLs production caused DD&A to increase $394 million. The effects of the production increase were partially offset by a decrease in the combined U.S., Canadian and international DD&A rate from $6.30 per Boe in 2001 to $5.88 per Boe in 2002. The drop in the DD&A rate was primarily due to reductions of carrying value of oil and gas properties recorded in the fourth quarter of 2001 and the second quarter of 2002.

Accretion of Asset Retirement Obligation Effective January 1, 2003, Devon adopted Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations*. We are using a cumulative effect approach to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depreciation. SFAS No. 143 requires liability recognition for retirement obligations associated with tangible long-lived assets, such as producing well sites, offshore production platforms and natural gas processing plants. The obligations included within the scope of SFAS No. 143 are those for which a company faces a legal obligation. The initial measurement of the asset retirement obligation is to record a separate liability at its fair value with an offsetting asset retirement cost recorded as an increase to the related property and equipment on the balance sheet. The asset retirement cost is depreciated using a systematic and rational method similar to that used for the associated property and equipment.

Because the asset retirement obligation is recorded at its discounted present value, Devon now records accretion expense to reflect the increase in the asset retirement obligation due to the passage of time. Devon recorded $36 million of such accretion expense during 2003.

Marketing and Midstream Operating Costs and Expenses *2003 vs. 2002* Marketing and midstream operating costs and expenses increased $366 million in 2003. Of this increase, approximately $347 million was the result of an increase in prices paid for gas and NGLs. An increase in third-party processed NGL volumes caused the remaining increase in 2003 costs and expenses. The increase in volumes was primarily related to new drilling and development in the Barnett Shale properties and an additional 24 days of production in 2003 due to the timing of the January 2002 Mitchell merger. This was partially offset by volumes lost as a result of processing plant dispositions.

2002 vs. 2001 Marketing and midstream operating costs and expenses increased $761 million in 2002. The Mitchell merger included significant marketing and midstream assets which accounted for substantially all of the increase in revenues.

General and Administrative Expenses ("G&A") Devon's 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. The other is the amount of G&A reimbursed by working interest owners of properties for which Devon serves 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,				
		2003	2003 vs 2002	2002	2002 vs 2001	2001
				(IN MILLIONS)		
Gross G&A	$	524	+35%	387	+56%	248
Capitalized G&A		(140)	+44%	(97)	+26%	(77)
Reimbursed G&A		(77)	+9%	(71)	+25%	(57)
Net G&A	$	307	+40%	219	+92%	114

2003 vs. 2002 Gross G&A increased $137 million. This increase was primarily related to increased activities resulting from the April 2003 Ocean merger, which added $92 million of costs and increased compensation and benefit costs. Included in the increase of compensation and benefit costs is $15 million related to the increase in the value of investments of deferred compensation plans that increases the obligation due to the plan participants. The increase in deferred compensation costs was partially offset by an $11 million increase in other income. Additionally, $14 million of the compensation and benefit costs related to an increase in pension related costs.

The increase in capitalized G&A of $43 million was primarily related to the April 2003 Ocean merger. Reimbursed G&A increased $6 million. The increase in reimbursed amounts also was primarily related to the Ocean merger, partially offset by a decline in reimbursements related to 2002 property divestitures.

2002 vs. 2001 Gross G&A increased $139 million, primarily due to increased activities resulting from the Anderson acquisition and Mitchell merger. Also included in 2002 gross G&A was $13 million related to the abandonment of certain office space assumed in the Santa Fe Snyder merger. The increase in capitalized G&A of $20 million was primarily related to the Anderson acquisition and Mitchell merger. The increase in reimbursed G&A of $14 million also was primarily related to the Anderson acquisition and Mitchell merger. This was partially offset by a decline in reimbursements related to 2002 property divestitures.

Reduction of Carrying Value of Oil and Gas Properties Under the full cost method of accounting, the net book value of oil and gas properties, less related deferred income taxes and asset retirement obligations, may not exceed a calculated "ceiling." The ceiling limitation is the discounted estimated after-tax future net revenues from proved oil and gas properties plus the cost of properties not subject to amortization. The ceiling test is imposed separately by country. In calculating future net revenues, current prices and costs are generally held constant indefinitely. The effect of hedges is included in the calculation of the future net revenues. The calculation also dictates the use of a 10% discount factor. Therefore, the ceiling limitation is not necessarily indicative of the properties' fair value. The costs to be recovered are compared to the ceiling on a quarterly basis. If the costs to be recovered exceed the ceiling, the excess is written off as an expense, except as discussed in the following paragraph.

A writedown is not required 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 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.

Under the purchase method of accounting for business combinations, acquired oil and gas properties are recorded at estimated fair value as of the date of purchase. Devon estimates such fair value using our estimates of future oil, gas and NGL prices. In contrast, the ceiling calculation dictates that prices in effect as of the last day of the applicable quarter are held constant indefinitely. Accordingly, the resulting value from the ceiling calculation is not necessarily indicative of the fair value of the reserves.

An expense recorded in one period may not be reversed in a subsequent period. This is true even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period.

During 2003, 2002 and 2001, Devon reduced the carrying value of its oil and gas properties by $68 million, $651 million and $883 million, respectively, due to the full cost ceiling limitations. The after-tax effect of these reductions in 2003, 2002 and 2001 was $36 million, $371 million and $533 million, respectively. The following table summarizes these reductions by geographic area.

		YEAR ENDED DECEMBER 31,					
		2003		2002		2001	
		GROSS	NET OF TAXES	GROSS	NET OF TAXES	GROSS	NET OF TAXES
				(IN MILLIONS)			
United States	$	—	—	—	—	449	281
Canada		—	—	651	371	434	252
International		68	36	—	—	—	—
Total	$	68	36	651	371	883	533

The 2003 reduction in carrying value was related to properties in Egypt, Russia and Indonesia. The Egyptian reduction was primarily due to poor results of a development well that was unsuccessful in the primary objective. Partially as a result of this well, we revised our Egyptian proved reserves downward. The Russian reduction was primarily the result of additional capital costs incurred as well as an increase in operating costs. The Indonesian reduction was primarily related to an increase in operating costs and a reduction in proved reserves. As a result, Devon's Egyptian, Russian and Indonesian costs to be recovered exceeded the related ceiling value by $26 million, $9 million and $1 million, respectively. These after-tax amounts resulted in pre-tax reductions of the carrying values of Devon's Egyptian, Russian and Indonesian oil and gas properties of $45 million, $19 million and $4 million, respectively, in the fourth quarter of 2003.

Additionally, during 2003, Devon elected to discontinue certain exploratory activities in Ghana, on certain properties in Brazil and on other smaller concessions. After meeting the drilling and capital commitments on these properties, we determined that these properties did not meet our internal criteria to justify further investment. Accordingly, Devon recorded a $43 million charge associated with the impairment of these properties. The after-tax effect of this reduction was $38 million.

The 2002 Canadian reduction was primarily the result of lower prices. The recorded fair values of oil and gas properties added from the Anderson acquisition in 2001 were based on expected future oil and gas prices. These expected prices were higher than the June 30, 2002, prices used to calculate the Canadian ceiling.

Based on oil, natural gas and NGL cash market prices as of June 30, 2002, Devon's Canadian costs to be recovered exceeded the related ceiling value by $371 million. This after-tax amount resulted in a pre-tax reduction of the carrying value of our Canadian oil and gas properties of $651 million in the second quarter of 2002. This reduction was the result of a sharp drop in Canadian gas prices during the last half of June 2002. The end of June reference prices used in the Canadian ceiling calculation, expressed in Canadian dollars based on an exchange ratio of $0.6585, were a NYMEX price of C$40.79 per barrel of oil and an AECO price of C$2.17 per MMBtu. The cash market prices of natural gas increased during the month of July 2002 prior to Devon's release of its second quarter results. This increase was not sufficient to offset the entire reduction calculated as of June 30.

The 2001 domestic and Canadian reductions were also primarily the result of lower prices. The oil and gas properties added from the Anderson acquisition and other smaller acquisitions in 2001 were recorded at fair values. These values were based on expected future oil and gas prices higher than the December 31, 2001 prices used to calculate the ceiling. The year-end 2001 prices used to calculate the ceiling were based on a NYMEX oil price of $19.84 per barrel, a Henry Hub gas price of $2.65 per MMBtu and an AECO gas price of C$3.67 per MMBtu.

Additionally, during 2001, Devon elected to abandon operations in Thailand, Malaysia, Qatar and on certain properties in Brazil. After meeting the drilling and capital commitments on these properties, we determined that these properties did not meet our internal criteria to justify further investment. Accordingly, Devon recorded a $96 million charge associated with the impairment of these properties. The after-tax effect of this reduction was $78 million.

Other Income (Expenses) The details of the changes in other income (expenses) between 2001 and 2003 are shown in the table below.

		2003	2002	2001
			(IN MILLIONS)	
Other income (expenses):				
Interest expense:				
Interest based on debt outstanding	$	(531)	(499)	(200)
Accretion of debt discount, net		(3)	(13)	(10)
Facility and agency fees		(1)	(2)	(1)
Amortization of capitalized loan costs		(12)	(8)	(3)
Capitalized interest		50	4	3
Early retirement premiums		—	(8)	(7)
Other		(5)	(7)	(2)
Total interest expense		(502)	(533)	(220)
Dividends on subsidiary's preferred stock		(2)	—	—
Effects of changes in foreign currency exchange rates		69	1	(11)
Change in fair value of financial instruments		1	28	(2)
Impairment of ChevronTexaco Corporation common stock		—	(205)	—
Other income		37	34	69
Total	$	(397)	(675)	(164)

A discussion of the significant other income (expense) items follows.

Interest Expense *2003 vs. 2002* Interest expense decreased $31 million in 2003. An increase in the average debt balance outstanding from $8.3 billion in 2002 to $8.9 billion in 2003 caused interest expense to increase $32 million. The increase in average debt outstanding was attributable primarily to the debt assumed in the April 2003 Ocean merger. The average interest rate on outstanding debt was 6.0% in both periods. Other items included in interest expense that are not related to the debt balance outstanding were $63 million lower in 2003. Of this decrease, $46 million related to capitalized interest, $10 million related to lower net accretion and $8 million related to a loss on the early extinguishment of the 8.75% senior notes in 2002. The increase in capitalized interest was primarily related to additional unproved properties acquired in the Ocean merger and the nature of those properties. The Ocean properties included significant deepwater Gulf and international exploratory properties and major development projects.

2002 vs. 2001 Interest expense increased $313 million in 2002. An increase in the average debt balance outstanding from $3.0 billion in 2001 to $8.3 billion in 2002 caused $319 million of the increase. The increase in average debt outstanding was attributable primarily to the long-term debt issued and assumed as a result of the Mitchell merger and Anderson acquisition.

The average interest rate on outstanding debt decreased from 6.6% in 2001 to 6.0% in 2002 due to favorable rates on borrowings under Devon's $3 billion term loan credit facility. This facility's rates averaged less than 3% during 2002. The overall rate decrease caused interest expense to decrease $20 million in 2002. Other items included in interest expense that are not related to the debt balance outstanding were $14 million higher in 2002. Of the $14 million increase in other items during 2002, $5 million related to the amortization of capitalized loan costs and $3 million related to an increase in the accretion of debt discounts. These increases were primarily due to the additional debt incurred as a result of the Mitchell merger and Anderson acquisition.

Effects of Changes in Foreign Currency Exchange Rates Devon's Canadian subsidiary has certain fixed-rate senior notes that are denominated in U.S. dollars. Changes in the exchange rate between the U.S. dollar and the Canadian dollar while the notes are outstanding increase or decrease the expected amount of Canadian dollars eventually required to repay the notes. In addition, Devon's Canadian subsidiary has cash and other working capital amounts denominated in U.S. dollars that also fluctuate in value with changes in the exchange rate. Such changes in the Canadian dollar equivalent balance of the debt and working capital are required to be included in determining net earnings for the period in which the exchange rate changes. The increase in the Canadian-to-U.S. dollar exchange rate from $0.6331 at December 31, 2002, to $0.7738 at December 31, 2003, resulted in a $69 million gain. The increase in the Canadian-to-U.S. dollar exchange rate from $0.6279 at December 31, 2001, to $0.6331 at December 31, 2002, resulted in a $1 million gain. The drop in the Canadian-to-U.S. dollar exchange rate from $0.6419 at October 15, 2001, (when the debt was assumed) to $0.6279 at December 31, 2001, resulted in an $11 million loss.

Impairment of ChevronTexaco Corporation Common Stock in 2002 In the fourth quarter of 2002, Devon recorded a $205 million other-than-temporary impairment of our investment in 7.1 million shares of ChevronTexaco common stock. We acquired these shares in our August 1999 acquisition of PennzEnergy Company. The shares are deposited with an exchange agent for possible exchange for $760 million of debentures that are exchangeable into the ChevronTexaco shares. We also assumed the debentures, which mature in August 2008, in the 1999 PennzEnergy acquisition.

At the closing date of the PennzEnergy acquisition, we initially recorded the ChevronTexaco common shares at their fair value, which was $95.38 per share, or an aggregate value of $677 million. Since then, as the ChevronTexaco shares have fluctuated in market value, the value of the shares on Devon's balance sheet has been adjusted to the applicable market value. Through September 30, 2002, any decreases in the value of the ChevronTexaco common shares were determined by Devon to be temporary in nature. Therefore, the changes in value were recorded directly to stockholders' equity and were not recorded in Devon's results of operations through September 30, 2002.

The determination that a decline in value of the ChevronTexaco shares is temporary or other than temporary is subjective and influenced by many factors. Among these factors are the significance of the decline as a percentage of the original cost and the length of time the stock price has been below original cost. Other factors are the performance of the stock price in relation to the stock price of its competitors within the industry, and the market in general and whether the decline is attributable to specific adverse conditions affecting ChevronTexaco.

Beginning in July 2002, the market value of ChevronTexaco common stock began a significant decline. The price per share decreased from $88.50 at June 30, 2002, to $69.25 per share at September 30, 2002, and to $66.48 per share at December 31, 2002. The year-end price of $66.48 represented a 25% decline since June 30, 2002, and a 30% decline from the original valuation in August 1999. As a result of the decline in value during the fourth quarter of 2002, Devon determined that the decline was other than temporary, as that term is defined by accounting rules. Therefore, the $205 million cumulative decrease in the value of the ChevronTexaco common shares from the initial acquisition in August 1999 to December 31, 2002, was recorded as a noncash charge to Devon's results of operations in the fourth quarter of 2002. Net of the applicable tax benefit, the charge reduced net earnings by $128 million.

During 2003, the share price of ChevronTexaco common stock has increased to $86.39 at December 31, 2003. As a result, the market value of Devon's investment in ChevronTexaco common stock increased $141 million from December 31, 2002, to December 31, 2003. The changes in the value of the shares since December 31, 2002, net of applicable taxes, have been recorded directly to stockholders' equity. However, depending on the future performance of ChevronTexaco's common stock, Devon may be required to record additional noncash charges in future periods if the value of the stock declines, and we determine that the declines are other than temporary.

Income Taxes *2003 vs. 2002* Devon's 2003 effective financial tax rate attributable to continuing operations was an expense of 23% compared to a benefit of 144% in 2002. The 2003 rate benefited from a statutory rate reduction enacted by the Canadian government that will be phased in through 2007. This rate reduction resulted in a $218 million benefit being recorded in 2003 related to the lower tax rates being applied to deferred tax liabilities outstanding as of December 31, 2002. Excluding the effects of the 2003 Canadian rate reduction, the impairment of ChevronTexaco stock in 2002 and the reduction of carrying value of oil and gas properties in 2003 and 2002, the effective financial tax expense rates were 33% and 23% in 2003 and 2002, respectively. These rates in both years were lower than the statutory federal tax rate primarily due to the tax benefits of certain foreign deductions.

2002 vs. 2001 Devon's 2002 effective financial tax rate attributable to continuing operations was a benefit of 144% compared to an effective financial tax rate expense of 18% in 2001. Excluding the effects of the impairment of ChevronTexaco stock in 2002 and the reduction of carrying value of oil and gas properties in 2002 and 2001, the effective financial tax expense rates were 23% and 37% in 2002 and 2001, respectively.

The 2002 rate, excluding the ChevronTexaco common stock impairment and the oil and gas property writedown, was lower than the statutory federal tax rate primarily due to the tax benefits of certain foreign deductions. The 2001 rate, excluding the oil and gas property writedowns, was higher than the statutory federal tax rate due to the effect of state taxes, goodwill amortization that was not deductible for income tax purposes and the effect of foreign income taxes.

Results of Discontinued Operations On April 18, 2002, Devon sold its Indonesian operations to PetroChina Company Limited for total cash consideration of $250 million. On October 25, 2002, we sold our Argentine operations to Petroleo Brasileiro S.A. for total cash consideration of $90 million. On January 27, 2003, we sold our Egyptian operations to IPR Transoil Corporation for total cash consideration of $7 million.

As a result, Devon reclassified its Indonesian, Argentine and Egyptian activities as discontinued operations. This reclassification affects not only the 2002 presentation of financial results, but also the presentation of all prior periods' results. Subsequent to the sale of its Egyptian and Indonesian operations, Devon acquired new Egyptian and Indonesian assets in the April 2003 Ocean merger. Amounts and activities related to these new Egyptian and Indonesian operations are included in Devon's continuing operations in 2003.

Following are the components of the net results of discontinued operations for the years 2002 and 2001.

	YEAR ENDED DECEMBER 31, 2002	2001
	(IN MILLIONS)	
Net gain on sale of discontinued operations	$ 31	—
Earnings from discontinued operations before income taxes	23	56
Income tax expense	9	25
Net results of discontinued operations	$ 45	31

Cumulative Effect of Change in Accounting Principle Effective January 1, 2003, Devon adopted SFAS No. 143 and recorded a cumulative-effect-type adjustment for an increase to net earnings of $16 million net of deferred taxes of $10 million.

Effective January 1, 2001, Devon adopted SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, and recorded a cumulative-effect-type adjustment to net earnings for a $49 million gain related to the fair value of derivatives that do not qualify as hedges. This gain included $46 million related to the option embedded in the debentures that are exchangeable into shares of ChevronTexaco common stock.

CAPITAL EXPENDITURES, CAPITAL RESOURCES AND LIQUIDITY

The following discussion of capital expenditures, capital resources and liquidity should be read in conjunction with the consolidated statements of cash flows included elsewhere in this report.

Capital Expenditures Cash payments for capital expenditures were $2.6 billion in 2003. This total includes $2.5 billion for the acquisition, drilling or development of oil and gas properties. These amounts compare to cash payments for capital expenditures of $3.4 billion in 2002 and $5.2 billion in 2001. The 2002 amounts included $1.7 billion related to the January 2002 Mitchell merger and $1.6 billion for other acquisitions and the drilling or development of oil and gas properties. The 2001 amounts included $3.5 billion related to the October 2001 Anderson acquisition and $1.6 billion for other acquisitions and the drilling or development of oil and gas properties.

The April 2003 Ocean merger did not affect cash paid for 2003 capital expenditures because the consideration given was Devon common stock. This differs from the January 2002 Mitchell merger, in which the consideration given was both Devon common stock and cash, and the October 2001 Anderson acquisition, in which the consideration given was cash. As a result, the Mitchell merger and Anderson acquisition did have an impact on capital expenditures paid in cash.

Capital Resources and Liquidity Devon's primary source of liquidity has historically been net cash provided by operating activities ("operating cash flow"). This source has been supplemented as needed by accessing credit lines and commercial paper markets and issuing equity securities and long-term debt securities. In 2002, another major source of liquidity was $1.4 billion generated from sales of oil and gas properties.

Operating Cash Flow

Operating cash flow continued to be a primary source of capital and liquidity in 2003. Operating cash flow in 2003 was $3.8 billion, compared to $1.8 billion in 2002 and $1.9 billion in 2001. The increase in operating cash flow in 2003 was primarily caused by the increase in revenues, partially offset by increased expenses, as discussed earlier in this section.

Devon's 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 out control and difficult to predict.

To mitigate some of the risk inherent in oil and natural gas prices, we have utilized price collars to set minimum and maximum prices on a portion of our production. Additionally, we have entered into various financial 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. The table below provides the volumes associated with these various arrangements as of December 31, 2003.

	PRICE COLLARS	PRICE SWAP CONTRACTS	FIXED-PRICE PHYSICAL DELIVERY CONTRACTS	TOTAL
Oil production (MMBbls)				
2004	28	23	—	51
2005	18	8	—	26
Natural gas production (Bcf)				
2004	437	3	16	456
2005	35	3	14	52

In addition to the above quantities, Devon also has fixed-price physical delivery contracts, for the years 2006 through 2011, covering Canadian natural gas production ranging from 8 Bcf to 14 Bcf per year. From 2012 through 2016, Devon also has Canadian gas volumes subject to fixed-price contracts, but the annual volumes are less than 1 Bcf.

By removing the price volatility from a portion of our oil and natural gas production, Devon has mitigated, but not eliminated, the potential effects of changing prices on operating cash flow. The combination of price collars, price swaps and fixed-price contracts currently in place represents approximately 65% of estimated 2004 oil production and 48% of estimated 2004 natural gas production.

It is Devon's policy to only enter into derivative contracts with investment grade rated counterparties deemed by management as competent and competitive market makers.

In February 2004, Devon announced that its capital expenditure budget for the year 2004 was approximately $2.8 billion. This capital budget, which includes capital for exploration and production, marketing and midstream and other corporate items, represents the largest planned use of available operating cash flow. To a certain degree, the ultimate timing of these capital expenditures is within Devon's control. Therefore, if oil and natural gas prices decline to levels below its acceptable levels, Devon could choose to defer a portion of these planned 2004 capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity. Based upon current oil and gas price expectations for 2004, Devon anticipates that its operating cash flow will exceed its planned capital expenditures and other cash requirements for the year. Devon currently intends to accumulate any excess cash to fund future years' debt maturities. Additional alternatives could be considered based upon the actual amount, if any, of such excess cash.

Credit Lines

Other sources of liquidity are Devon's revolving lines of credit. We have $1 billion of unsecured long-term credit facilities (the "Credit Facilities"). The Credit Facilities include a U.S. facility of $725 million (the "U.S. Facility") and a Canadian facility of $275 million (the "Canadian Facility"). The $725 million U.S. Facility consists of a Tranche A facility of $200 million and a Tranche B facility of $525 million.

The Tranche A facility matures on October 15, 2004. Devon may borrow funds under the Tranche B facility until June 2, 2004 (the "Tranche B Revolving Period"). Devon may request that the Tranche B Revolving Period be extended an additional 364 days by notifying the agent bank of such request between 30 and 60 days prior to the end of the Tranche B Revolving Period. On June 2, 2004, at the end of the Tranche B Revolving Period, Devon may convert the then outstanding balance under the Tranche B facility to a one-year term loan by paying the Agent a fee of 25 basis points. The applicable borrowing rate would be at LIBOR plus 112.5 basis points. On December 31, 2003, there were no borrowings outstanding under the $725 million U.S. Facility. The available capacity under the U.S. Facility as of December 31, 2003, net of outstanding letters of credit, was approximately $586 million.

Devon may borrow funds under the $275 million Canadian Facility until June 2, 2004 (the "Canadian Facility Revolving Period"). Devon may request that the Canadian Facility Revolving Period be extended an additional 364 days by notifying the agent bank of such request between 30 and 60 days prior to the end of the Canadian Facility Revolving Period. Debt outstanding as of the end of the Canadian Facility Revolving Period is payable in semiannual installments of 2.5% each for the following five years. The final installment is due five years and one day following the end of the Canadian Facility Revolving Period. On December 31, 2003, there were no borrowings under the $275 million Canadian facility. The available capacity under the Canadian Facility as of December 31, 2003, net of outstanding letters of credit, was approximately $214 million.

Under the terms of the Credit Facilities, Devon has the right to reallocate up to $100 million of the unused Tranche B facility maximum credit amount to the Canadian Facility. Conversely, Devon also has the right to reallocate up to $100 million of unused Canadian Facility maximum credit amount to the Tranche B Facility.

Amounts borrowed under the Credit Facilities bear interest at various fixed rate options that Devon may elect for periods up to six months. Such rates are generally less than the prime rate. We may also elect to borrow at the prime rate. The Credit Facilities provide for an annual facility fee of $1.4 million that is payable quarterly in arrears. We intend to renew the Credit Facilities in 2004.

Devon also has access to short-term credit under its commercial paper program. Total borrowings under the U.S. Facility and the commercial paper program may not exceed $725 million. Commercial paper debt generally has a maturity of between seven to 90 days, although it can have a maturity of up to 365 days. Devon had no commercial paper debt outstanding at December 31, 2003.

Devon's Credit Facilities contain only one material financial covenant. This covenant requires Devon to maintain a ratio of total funded debt to total capitalization of no more than 65%. The credit agreements contain definitions of total funded debt and total capitalization that include adjustments to the respective amounts reported in Devon's consolidated financial statements. In accordance with the agreements, total funded debt excludes the debentures that are exchangeable into shares of ChevronTexaco common stock. Also, total capitalization is adjusted to add back noncash financial writedowns such as full cost ceiling property impairments or goodwill impairments. As of December 31, 2003, Devon was in compliance with this covenant.

Devon's access to funds from its Credit Facilities is not restricted under any "material adverse condition" 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 prospects considered as a whole, the borrower's ability to make timely debt payments, or the enforceability of material terms of the credit agreement. While Devon's Credit Facilities and its $3 billion term loan credit facility include covenants that require Devon to report a condition or event having a material adverse effect on Devon, the obligation of the banks to fund the Credit Facilities is not conditioned on the absence of a material adverse effect.

Ocean Debt

In connection with the Ocean merger, Devon assumed $1.8 billion of debt. A summary of this debt is as follows:

	FAIR VALUE OF DEBT ASSUMED AS OF APRIL 25, 2003 (IN MILLIONS)
Revolving credit line	$ 160
Note payable	50
Senior notes and senior subordinated notes:	
7.875% due August 2003 (principal of $100 million)	102
7.625% due July 2005 (principal of $125 million)	139
4.375% due October 2007 (principal of $400 million)	410
8.375% due July 2008 (principal of $200 million)	208
7.250% due September 2011 (principal of $350 million)	406
8.250% due July 2018 (principal of $125 million)	147
7.500% due September 2027 (principal of $150 million)	169
Other	6
	1,797
Less amount classified as current as of April 25, 2003	361
Long-term debt	$ 1,436

Change of control provisions required the outstanding borrowings under the credit line and note payable to be fully paid immediately. Additionally, Devon was required to extend purchase offers for certain senior notes and the senior subordinated notes. As a result of these purchase offers, which expired on June 13, 2003, Devon paid $118 million for the aggregate principal amount tendered. The purchase price for each offer was 101 percent of the principal amount of the notes tendered plus accrued and unpaid interest to and including the purchase date. All notes that were not tendered remain outstanding except as described below.

Included in the $118 million of debt retired pursuant to the purchase offer were $13 million of the 8.375% notes and $57 million of the 7.875% notes. The remaining $195 million of 8.375% notes were called and redeemed on July 1, 2003. Additionally, the remaining $43 million of 7.875% senior notes were paid August 1, 2003, when they were due.

Debt Ratings

Devon receives debt ratings from the major ratings agencies in the United States. In determining Devon's debt rating, 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. Other considerations include capital allocation challenges, liquidity, asset quality, cost structure, reserve mix and commodity pricing levels.

Devon's current debt ratings are BBB with a stable outlook by Standard & Poor's, Baa2 with a negative outlook by Moody's and BBB with a stable outlook by Fitch. There are no "rating triggers" in any of Devon's contractual obligations that would accelerate scheduled maturities should Devon's debt rating fall below a specified level. Certain of Devon's agreements related to its oil and natural gas hedges do contain provisions that could require Devon to provide cash collateral in situations where our liability under the hedge is above a certain dollar threshold and where our debt rating is below investment grade (BBB- or Baa3). However, Devon's liability under these agreements would only exceed the threshold level in circumstances where the market prices for oil or natural gas were rising. It is unlikely that Devon's debt rating would be subjected to downgrades to non-investment grade levels during such a period of rising oil and natural gas prices.

Devon's cost of borrowing under its Credit Facilities and on the $635 million borrowed under its $3 billion term loan facility is predicated on its corporate debt rating. Therefore, even though a ratings downgrade would not accelerate scheduled maturities, it would adversely impact Devon's interest rate on its variable rate debt. Under the terms of the Credit Facilities and the term loan credit facility, a one-notch downgrade would increase Devon's fully drawn borrowing rates by 25 basis points for each facility. The average borrowing costs for the Credit Facilities would increase from LIBOR plus 95 basis points to LIBOR plus 120 basis points. The borrowing costs for the term loan facility would increase from LIBOR plus 100 basis points to LIBOR plus 125 basis points. A ratings downgrade could also adversely impact our ability to economically access future debt markets.

As of December 31, 2003, Devon was not aware of any potential ratings downgrades being contemplated by the rating agencies.

Contractual Obligations

A summary of Devon's contractual obligations as of December 31, 2003, is provided in the following table.

	PAYMENTS DUE BY YEAR							
		2004	2005	2006	2007	2008	AFTER 2008	TOTAL
					(IN MILLIONS)			
Long-term debt	$	337	497	1,291	400	761	5,606	8,892
Drilling obligations		437	189	55	1	—	—	682
Firm transportation agreements		100	68	57	46	36	158	465
Operating leases:								
Office and equipment leases		47	40	36	28	24	85	260
Spar leases		11	15	15	15	15	243	314
FPSO leases		20	20	20	20	20	36	136
Other		6	7	6	5	5	4	33
Total	$	958	836	1,480	515	861	6,132	10,782

Firm transportation agreements represent "ship or pay" arrangements whereby Devon has committed to ship certain volumes of gas for a fixed transportation fee. We have entered into these agreements to aid us in moving our gas production to market. Devon has sufficient production to utilize the majority of these transmission services.

We 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 operating leases are for 20-year terms and contain various options whereby Devon may purchase the lessors' interests in the spars. Devon has guaranteed that the spars will have residual values at the end of the operating leases equal to at least 10% of the fair value of the spars at the inception of the leases. The total guaranteed value is $20 million in 2022. However, this amount may be reduced under the terms of the lease agreements.

Devon also has two floating, production, storage and offloading (FPSO) facilities that are being leased under operating lease arrangements. One FPSO is being used in the Panyu project offshore China, and the other is being used in the Zafiro field offshore Equatorial Guinea. The China lease expires in September 2009 and the Equatorial Guinea lease expires in July 2011.

The above table does not include $200 million of letters of credit that have been issued by commercial banks on Devon's behalf which, if funded, would become borrowings under Devon's revolving credit facility. Most of these letters of credit have been granted by Devon's financial institutions to support Devon's international and Canadian drilling commitments. The $8.9 billion of long-term debt shown in the table excludes $1 million of net discounts and a $27 million fair value adjustment. Both of these items are included in the December 31, 2003, book balance of the debt.

Pension Funding and Obligations

Devon's pension expense is recognized on an accrual basis over employees' approximate service periods. It is generally calculated independent of funding decisions or requirements. Devon recognized expense for its defined benefit pension plans of $35 million, $16 million and $7 million in 2003, 2002 and 2001, respectively. Devon estimates that its pension expense will approximate $24 million in 2004.

As compared to the "projected benefit obligation," Devon's qualified and nonqualified defined benefit plans were underfunded by $137 million and $179 million at December 31, 2003 and 2002, respectively. The decrease in the underfunded amount during 2003 was primarily caused by gains on investments and cash contributions of $67 million made to the plans by Devon, partially offset by increases in the benefit obligations. A detailed reconciliation of the 2003 activity is included in Note 13 to the accompanying consolidated financial statements. Of the $137 million underfunded status at the end of 2003, $91 million is attributable to various nonqualified defined benefit plans which have no plan assets. However, Devon has established certain trusts to fund the benefit obligations of such nonqualified plans. As of December 31, 2003, these trusts had investments with a market value of $66 million. The value of these trusts is included in noncurrent other assets in the accompanying consolidated balance sheets.

As compared to the "accumulated benefit obligation," Devon's qualified defined benefit plans were underfunded by $22 million at December 31, 2003. The accumulated benefit obligation differs from the projected benefit obligation in that the former includes no assumption about future compensation levels. Devon's current intentions are to fund this accumulated benefit obligation deficit during 2004 and provide sufficient funding in subsequent years to ensure the accumulated benefit obligation remains funded. The actual amount of contributions required during this period will depend on investment returns from the plan assets and any changes in actuarial assumptions made during the same period.

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. Devon believes 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.

Devon assumed that its plan assets would generate a long-term weighted average rate of return of 8.25% and 8.27% at December 31, 2003 and 2002, respectively. 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 Devon's 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.

Devon believes that its long-term asset allocation on average will approximate the targeted allocation. Devon regularly reviews its actual asset allocation and periodically rebalances 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 Devon's long-term rate of return assumption of 100 basis points (from 8.25% to 7.25%) would increase the expected 2004 pension expense by approximately $4 million.

Devon discounted its future pension obligations using a weighted average rate of 6.23% at December 31, 2003, compared to 6.72% at December 31, 2002. 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. Devon considers 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 6.23% to 5.98%) would increase Devon's pension liability at December 31, 2003, by approximately $16 million, and increase its estimated 2004 pension expense by approximately $2 million.

At December 31, 2003, Devon had unrecognized actuarial losses of $119 million. These losses will be recognized as a component of pension expense in future years. Devon estimates that approximately $7 million and $6 million of the unrecognized actuarial losses will be included in pension expense in 2004 and 2005, respectively. The $7 million estimated to be recognized in 2004 is a component of the total estimated 2004 pension expense of $24 million referred to earlier in this discussion.

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

Other Cash Uses

Devon's common stock dividends were $39 million, $31 million and $25 million in 2003, 2002 and 2001, respectively. Devon also paid $10 million of preferred stock dividends in 2003, 2002 and 2001.

During 2001, we repurchased 3,754,000 shares of Devon common stock at an aggregate cost of $190 million or $50.71 per share. We also repurchased shares of common stock in 2001 under an odd-lot repurchase program. Pursuant to this program, Devon purchased and retired 232,000 shares of its common stock for a total cost of $14 million, or $57.40 per share.

CRITICAL ACCOUNTING POLICIES

Full Cost Ceiling Calculations Devon follows the full cost method of accounting for its 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. If our capitalized costs are in excess of the calculated ceiling, the excess must be written off as an expense. The ceiling limitation is imposed separately for each country in which Devon has oil and gas properties.

Devon's discounted present value of its 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 Devon's reserve estimates are prepared by outside consultants, while other reserve estimates are prepared by Devon's engineers. See Note 18 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 four years, Devon's annual revisions to its reserve estimates have averaged approximately 2% 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 prices and costs in effect as of the last day of the period are generally held constant indefinitely. Therefore, the future net revenues associated with the estimated proved reserves are not based on Devon's assessment of future prices or costs. 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.

The ceiling calculation also dictates that a 10% discount factor is to be used to calculate the present value of net cash flows.

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 cyclical and, on any particular day at the end of a quarter, can be either substantially higher or lower than Devon's long-term price forecast that is a barometer for true fair value. Oil and gas property writedowns that result from applying the full cost ceiling limitation are caused by fluctuations in price, not quantities of reserves. Therefore, such writedowns should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves.

Derivative Instruments Devon enters into oil and gas financial instruments to manage its exposure to oil and gas price volatility. We have also entered into interest rate swaps to manage our exposures to interest rate volatility. The interest rate swaps mitigate either the effects on interest expense for variable-rate debt instruments or the debt fair values for fixed-rate debt. Devon is not involved in any speculative trading activities of derivatives. All derivatives are accounted for in accordance with SFAS No. 133 and are recognized on the balance sheet at their fair value.

A substantial portion of Devon's derivatives consists of contracts that hedge the price of future oil and natural gas production. These derivative contracts are cash flow hedges that qualify for hedge accounting treatment under SFAS No. 133. Therefore, while fair values of such hedging instruments must be estimated as of the end of each reporting period, the changes in the fair values are not included in Devon's consolidated results of operations. Instead, the changes in fair value of these hedging instruments, net of tax, are recorded directly to stockholders' equity until the hedged oil or natural gas quantities are produced. To qualify for hedge accounting treatment, Devon designates its cash flow hedge instruments as such on the date the derivative contract is entered into or the date of a business combination which includes cash flow hedge instruments. Additionally, Devon documents all relationships between hedging instruments and hedged items as well as its risk-management objective and strategy for undertaking various hedge transactions. Devon also assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. If Devon fails to meet the requirements for using hedge accounting treatment, the changes in fair value of these hedging instruments would not be recorded directly to equity but in the consolidated results of operations.

The estimates of the fair values of Devon's commodity derivative contracts require substantial judgment. For these contracts, 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 Devon's current borrowing rates under our revolving credit facilities. In addition, we estimate the option value of price floors and price caps using the

Black-Scholes option pricing model. These pricing and discounting variables are sensitive to market volatility as well as changes in forward prices, regional price differentials and interest rates. Fair values of Devon's other derivative contracts require less judgment to estimate and are primarily based on quotes from independent third parties such as counterparties or brokers.

Business Combinations Devon has 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. 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.

There are various assumptions made by Devon 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, Devon prepares estimates of oil, natural gas and NGL reserves. These estimates are based on work performed by Devon's 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 current 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 Devon's estimates of future oil, natural gas and NGL prices. 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 analyses. Forecasts of future prices from independent third parties are noted when Devon makes its pricing estimates.

Devon estimates future prices to apply to the estimated reserve quantities acquired. We also 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 Devon's cost of capital.

Devon also applies these same general principles in arriving at 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 Devon considers 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 Devon's 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 Devon assumes in the acquisition. This debt must be recorded at the estimated fair value as if Devon had issued such debt. However, significant judgment on Devon's behalf is usually not required in these situations due to the existence of comparable market values of debt issued by Devon's peer companies.

Except for the 2002 Mitchell merger, Devon's 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 its 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 were also acquired by Devon. As a result, 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, Devon 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 Devon's estimated fair value of the marketing and midstream facilities and equipment.

In addition to the valuation methods described above, Devon performs 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 company analysis, Devon reviews the public stock market trading multiples for selected publicly traded independent exploration and production companies. The selected companies have financial and operating characteristics, such as market capitalization, location of proved reserves and the characterization of those reserves that Devon deems to be similar to those of the party to the proposed business combination. These comparable company multiples are compared to the proposed business combination company multiples for reasonableness.

In a comparable transactions analysis, Devon reviews certain acquisition multiples for selected independent exploration and production company transactions and oil and gas asset packages announced recently. The comparable transaction multiples are compared to the proposed business combination transaction multiples for reasonableness.

In a premiums paid analysis, Devon uses 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. Devon uses this information to determine the mean and median premiums paid and compares them to the proposed business combination premium for reasonableness.

Valuation of Goodwill Goodwill and intangible assets with indefinite useful lives are tested for impairment at least annually. This requires Devon to estimate the fair values of its 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 on an annual basis.

Drilling and Mineral Rights In 2003, the Securities Exchange Commission ("SEC") inquired of the Financial Accounting Standards Board regarding the application of certain provisions of SFAS No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets*, to oil and gas companies. SFAS Nos. 141 and 142 became effective for transactions subsequent to June 30, 2001. SFAS No. 141 requires that all business combinations initiated after June 30, 2001, be accounted for using the purchase method and that acquired intangible assets be disaggregated and reported separately from goodwill. Specifically, the SEC's inquiry is based on whether costs of contract-based drilling and mineral use rights ("mineral rights") should be recorded and disclosed as intangible assets under the guidance in SFAS Nos. 141 and 142. The current practice for Devon and the industry is to present oil and gas related assets, including mineral rights, as property and equipment (tangible assets) on the balance sheet. Since June 30, 2001, Devon has entered into business combinations with Anderson, Mitchell and Ocean with an aggregate accounting purchase price of $18.2 billion. The majority of the purchase price has been allocated to oil and gas property.

An Emerging Issues Task Force Working Group ("EITF") has been created to research the accounting and disclosure treatment of mineral rights for oil and gas companies. As a result, the EITF has added Issue No. 03-O, "Whether Mineral Rights are Tangible or Intangible Assets," and Issue No. 03-S, "Application of FASB Statement No. 142, Goodwill and Other Intangible Assets, to Oil and Gas Companies." Currently, Devon does not believe that generally accepted accounting principles require the classification of mineral rights as intangible assets and continues to classify these assets as oil and gas properties. However, the decisions of the EITF may affect how Devon classifies these assets in the future. If the EITF ultimately determines that SFAS Nos. 141 and 142 require oil and gas companies to classify mineral rights as separate intangible assets, the amounts included in oil and gas properties on the balance sheet that would be reclassified are not expected to exceed the following amounts:

		DECEMBER 31, 2003	DECEMBER 31, 2002
		(IN MILLIONS)	
Intangible proved drilling and mineral rights, net of accumulated DD&A	$	7,156	3,057
Intangible unproved drilling and mineral rights	$	2,678	1,777
Total intangible drilling and mineral rights	$	9,834	4,834

Amounts to be reclassified would be impacted by the provisions of the EITF consensus. The ultimate reclassification amount could be materially different than the amounts above. Numerous decisions that could be included in the consensus would impact the composition and amortization of the intangible assets, if any.

Devon believes that cash flows and results of operations would not be affected. Such intangible assets would likely continue to be depleted and assessed for impairment in accordance with Devon's accounting policies as prescribed under the full cost method of accounting for oil and gas properties. Further, Devon does not believe the classification of the mineral rights as intangible assets would affect compliance with covenants under our debt agreements.

Impact of Recently Issued Accounting Standards Not Yet Adopted In December 2003, the FASB issued FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities*, ("FIN 46R") which addresses how a business enterprise should evaluate whether it has a controlling financial interest in an entity through means other than voting rights and accordingly should consolidate the entity. FIN 46R replaces FASB Interpretation No. 46, *Consolidation of Variable Interest Entities*, which was issued in January 2003. Devon will be required to apply FIN 46R to variable interests in variable interest entities ("VIEs") created after December 31, 2003. For variable interests in VIEs created before January 1, 2004, FIN 46R will be applied beginning on January 1, 2005. For any VIEs that must be consolidated under FIN 46R that were created before January 1, 2004, the assets, liabilities and noncontrolling interests of the VIE initially would be measured at their carrying amounts. Any difference between the net amount added to the consolidated balance sheet and any previously recognized interest would be recognized as the cumulative effect of a change in accounting principle. If determining the carrying amounts is not practicable, fair value at the date FIN 46R first applies may be used to measure the assets, liabilities and noncontrolling interest of the VIE. Devon owns no interests in variable interest entities; therefore, FIN 46R will not affect Devon's consolidated financial statements.

SFAS Statement No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*, was issued in May 2003. SFAS No. 150 establishes standards for the classification and measurement of certain financial instruments with characteristics of both liabilities and equity. SFAS No. 150 also includes required disclosures for financial instruments within its scope. SFAS No. 150 was effective for instruments entered into or modified after May 31, 2003 and otherwise will be effective as of January 1, 2004, except for mandatorily redeemable financial instruments. For certain mandatorily redeemable financial instruments, SFAS No. 150 will be effective on January 1, 2005. The effective date has been deferred indefinitely for certain other types of mandatorily redeemable financial instruments. Devon currently does not have any financial instruments that are within the scope of SFAS No. 150.

2004 ESTIMATES

The forward-looking statements provided in this discussion are based on management's examination of historical operating trends, the information which was used to prepare the December 31, 2003, 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.

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 below.

Also, the financial results of Devon's foreign operations are subject to currency exchange rate risks. Additional risks are discussed below in the context of line items most affected by such risks.

Specific Assumptions and Risks Related to Price and Production Estimates 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, Devon's oil, gas and NGL prices may vary considerably due to differences between regional markets, 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.

Estimates for Devon's 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. 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.

Estimates for Devon's 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.

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 and meteorological events including, but not limited to, hurricanes and numerous other factors. The following forward-looking statements were prepared assuming demand, curtailment, producibility and general market conditions for Devon's oil, natural gas and NGLs during 2004 will be substantially similar to those of 2003, unless otherwise noted.

Unless otherwise noted, all of the following dollar amounts are expressed in U.S. dollars. Amounts related to Canadian operations have been converted to U.S. dollars using a projected average 2004 exchange rate of $0.7600 U.S. dollar to $1.00 Canadian. The actual 2004 exchange rate may vary materially from this estimate. Such variations could have a material effect on the following estimates.

Though Devon has completed several major property acquisitions and dispositions in recent years, these transactions are opportunity driven. Thus, the following forward-looking data excludes the financial and operating effects of potential property acquisitions or divestitures during the year 2004.

GEOGRAPHIC REPORTING AREAS FOR 2004

The following estimates of production, average price differentials and capital expenditures are provided separately for each of the following geographic areas:

- the United States onshore;
- the United States offshore, which encompasses all oil and gas properties in the Gulf of Mexico;
- Canada; and
- International, which encompasses all oil and gas properties that lie outside of the United States and Canada.

YEAR 2004 POTENTIAL OPERATING ITEMS

Oil, Gas and NGL Production Set forth in the following paragraphs are individual estimates of Devon's oil, gas and NGL production for 2004. On a combined basis, Devon estimates its 2004 oil, gas and NGL production will total between 256 and 261 MMBoe. Of this total, approximately 95% is estimated to be produced from reserves classified as "proved" at December 31, 2003.

Oil Production We expect oil production in 2004 to total between 78 and 80 MMBbls. Of this total, approximately 97% is estimated to be produced from reserves classified as "proved" at December 31, 2003. The expected ranges of production by area are as follows:

	(MMBBLS)
United States Onshore	15 to 15
United States Offshore	18 to 19
Canada	14 to 14
International	31 to 32

Oil Prices – Fixed Through various price swaps, Devon has fixed the price it will receive in 2004 on a portion of its oil production. The following table includes information on this fixed-price production by area. Where necessary, the prices have been adjusted for certain transportation costs that are netted against the prices recorded by Devon.

	BBLS/DAY	PRICE/BBL	MONTHS OF PRODUCTION
United States Onshore	11,000	$ 27.51	Jan – Dec
United States Offshore	18,000	$ 27.16	Jan – Dec
Canada	15,000	$ 27.53	Jan – Dec
International	20,000	$ 26.03	Jan – Dec

Oil Prices – Floating Devon's 2004 average prices for each of its 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 West Texas Intermediate crude oil delivered at Cushing, Oklahoma.

	EXPECTED RANGE OF OIL PRICES LESS THAN NYMEX PRICE
United States Onshore	($3.00) to ($2.00)
United States Offshore	($4.50) to ($2.50)
Canada	($6.50) to ($4.50)
International	($5.50) to ($3.00)

We have also entered into costless price collars that set a floor and ceiling price for a portion of our 2004 oil production that is otherwise subject to floating prices. The floor and ceiling prices related to domestic and Canadian oil production are based on the NYMEX price. The floor and ceiling prices related to international oil production are based on the Brent price. If the NYMEX or Brent price is outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. Any such settlements will either increase or decrease Devon's oil revenues for the period. Because Devon's oil volumes are often sold at prices that differ from the NYMEX or Brent price due to differing quality (i.e., sweet crude versus sour crude) and transportation costs from different geographic areas, the floor and ceiling prices of the various collars do not reflect actual limits of Devon's realized prices for the production volumes related to the collars.

We have adjusted the international oil prices shown in the following table to a NYMEX-based price, using Devon's estimates of 2004 differentials between NYMEX and the Brent price upon which the collars are based.

To simplify presentation, we have aggregated costless collars as of December 31, 2003, in the following table according to similar floor prices and similar ceiling prices. The floor and ceiling prices shown are weighted averages of the various collars in each aggregated group.

AREA (RANGE OF FLOOR PRICES/ CEILING PRICES)	BBLS/DAY	WEIGHTED AVERAGE FLOOR PRICE PER BBL	WEIGHTED AVERAGE CEILING PRICE PER BBL	MONTHS OF PRODUCTION
United States Onshore				
($20.00 - $21.50 / $26.50 - $27.90)	3,000	$ 20.83	$ 27.43	Jan – Dec
($20.00 - $22.00 / $28.35 - $29.75)	6,000	$ 21.42	$ 29.25	Jan – Dec
($22.00 - $22.00 / $30.10 - $30.60)	2,000	$ 22.00	$ 30.35	Jan – Dec
United States Offshore				
($20.00 - $22.00 / $27.55 - $29.75)	6,000	$ 21.42	$ 28.75	Jan – Dec
($22.00 - $22.00 / $30.00 - $31.40)	7,000	$ 22.00	$ 30.74	Jan – Dec
Canada				
($20.00 - $21.50 / $26.50 - $27.70)	3,000	$ 20.50	$ 27.07	Jan – Dec
($20.00 - $22.00 / $28.00 - $29.20)	5,000	$ 21.10	$ 28.69	Jan – Dec
($22.00 - $22.00 / $29.80 - $32.35)	8,000	$ 22.00	$ 31.14	Jan – Dec
International				
($22.31 - $22.31 / $30.11 - $31.51)	27,000	$ 22.31	$ 30.82	Jan – Dec
($22.31 - $22.31 / $31.56 - $32.81)	10,000	$ 22.31	$ 31.96	Jan – Dec

Gas Production We expect 2004 gas production to total between 936 Bcf and 948 Bcf. Of this total, approximately 93% is estimated to be produced from reserves classified as "proved" at December 31, 2003. The expected ranges of production by area are as follows:

	(BCF)
United States Onshore	489 to 494
United States Offshore	148 to 150
Canada	292 to 297
International	7 to 7

Gas Prices – Fixed Through various price swaps and fixed-price physical delivery contracts, we have fixed the price we will receive in 2004 on a portion of our natural gas production. The following table includes information on this fixed-price production by area. Where necessary, the prices have been adjusted for certain transportation costs that are netted against the prices recorded by Devon, and the prices have also been adjusted for the Btu content of the gas hedged.

	MCF/DAY	PRICE/MCF	MONTHS OF PRODUCTION
United States Onshore	8,435	$ 3.10	Jan – Dec
Canada	43,578	$ 2.76	Jan – Jun
Canada	41,920	$ 2.79	Jul – Dec

Gas Prices – Floating For the natural gas production for which prices have not been fixed, Devon's 2004 average prices for each of its 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*.

	EXPECTED RANGE OF GAS PRICES LESS THAN NYMEX PRICE
United States Onshore	($0.80) to ($0.30)
United States Offshore	($0.25) to ($0.05)
Canada	($1.10) to ($0.60)
International	($3.00) to ($2.00)

We have also entered into costless price collars that set a floor and ceiling price for a portion of our 2004 natural gas production that otherwise is subject to floating prices. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. Any such settlements will either increase or decrease Devon's gas revenues for the period. Because Devon's gas volumes are often sold at prices that differ from the related regional indices, and due to differing Btu contents of gas produced, the floor and ceiling prices of the various collars do not reflect actual limits of Devon's realized prices for the production volumes related to the collars.

We have adjusted the prices shown in the following table to a NYMEX-based price, using Devon's estimates of 2004 differentials between NYMEX and the specific regional indices upon which the collars are based. The floor and ceiling prices related to the domestic collars are based on various regional first-of-the-month price indices as published monthly by *Inside FERC.* The floor and ceiling prices related to the Canadian collars are based on the AECO index as published by the *Canadian Gas Price Reporter.*

To simplify presentation, we have aggregated costless collars in the following table according to similar floor prices and similar ceiling prices. The floor and ceiling prices shown are weighted averages of the various collars in each aggregated group.

		WEIGHTED AVERAGE		
AREA (RANGE OF FLOOR PRICES/CEILING PRICES)	MMBTU/DAY	FLOOR PRICE PER MMBTU	CEILING PRICE PER MMBTU	MONTHS OF PRODUCTION
United States Onshore				
($3.32 - $4.22 / $4.97 - $6.37)	110,000	$ 3.77	$ 5.91	Jan – Dec
($3.32 - $4.47 / $6.47 - $7.35)	215,000	$ 4.10	$ 6.87	Jan – Dec
($3.32 - $4.00 / $7.45 - $7.85)	45,000	$ 3.54	$ 7.62	Jan – Dec
($3.50 - $4.07 / $8.02 - $8.86)	100,000	$ 3.61	$ 8.37	Jan – Dec
($4.00 - $4.15 / $7.00 - $7.00)	40,000	$ 4.06	$ 7.00	Jan – Jun
($4.02 - $4.03 / $6.98 - $6.99)	50,000	$ 4.03	$ 6.99	Jul – Dec
United States Offshore				
($3.25 - $3.25 / $7.00 - $7.00)	10,000	$ 3.25	$ 7.00	Jan – Dec
($3.50 - $3.50 / $7.40 - $7.90)	50,000	$ 3.50	$ 7.74	Jan – Dec
($4.00 - $4.00 / $7.43 - $8.80)	130,000	$ 4.00	$ 7.71	Jan – Dec
($4.00 - $4.12 / $7.00 - $7.00)	60,000	$ 4.07	$ 7.00	Jan – Jun
($4.00 - $4.00 / $7.00 - $7.00)	50,000	$ 4.00	$ 7.00	Jul – Dec
Canada				
($4.10 - $4.21 / $6.46 - $7.07)	60,000	$ 4.18	$ 6.76	Jan – Dec
($4.06 - $4.59 / $7.17 - $7.94)	140,000	$ 4.29	$ 7.51	Jan – Dec
($3.98 - $4.13 / $8.43 - $8.75)	60,000	$ 4.04	$ 8.63	Jan – Dec
($3.96 - $4.25 / $9.14 - $9.64)	70,000	$ 4.06	$ 9.33	Jan – Dec
($3.96 - $4.05 / $9.91 - $10.54)	25,000	$ 4.02	$ 10.37	Jan – Dec
($4.60 - $4.85 / $6.53 - $6.53)	90,000	$ 4.75	$ 6.53	Jan – Jun
($4.60 - $4.86 / $6.53 - $6.71)	70,000	$ 4.73	$ 6.61	Jul – Dec

In the April 2003 Ocean merger, Devon assumed an obligation under a forward sale contract to deliver contractual quantities of 55,600 MMBtu per day in 2004. Under the terms of this forward sale, the purchaser is obligated to make additional payments in the event the spot price exceeds $3.00 per MMBtu in 2004. The spot price is based on a relevant regional first-of-the-month price index as published monthly by *Inside FERC* as determined by Devon. As part of the purchase price allocation, Devon recorded deferred revenues related to this forward gas sale based on the $3.00 price. These deferred revenues will be recognized during 2004. If the monthly spot prices exceed these prices, Devon will receive additional cash payments from the purchaser, which will also be recorded as gas revenues. Therefore, if the monthly spot prices for 2004 exceed $3.00 per MMBtu, Devon will recognize gas revenues on the related quantities at a floating market price but will receive actual cash payments equal only to the difference between the floating market price and $3.00. If the monthly spot prices for 2004 are equal to or less than $3.00 per MMBtu, Devon will recognize gas revenues on the related quantities at a fixed price of $3.00 and will receive no cash consideration for the delivered quantities of gas.

NGL Production We expect our 2004 production of NGLs to total between 22 MMBbls and 23 MMBbls. Of this total, 95% is estimated to be produced from reserves classified as "proved" at December 31, 2003. The expected ranges of production by area are as follows:

	(MMBBLS)
United States Onshore	16 to 17
United States Offshore	1 to 1
Canada	5 to 5

Marketing and Midstream Revenues and Expenses Devon's 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 arrangements 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 2004 marketing and midstream revenues will be between $1.07 billion and $1.14 billion, and marketing and midstream expenses will be between $860 million and $910 million.

Production and Operating Expenses Devon's 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 Devon's property base, changes in production tax rates, changes in the general price level of services and materials that are used in the operation of the properties and the amount of repair and workover activity required. 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 2004 lease operating expenses will be between $1.05 billion and $1.12 billion and transportation costs will be between $220 million and $230 million. We estimate that production taxes will be between 3.1% and 3.6% of consolidated oil, natural gas and NGL revenues, excluding revenues related to hedges upon which production taxes are not incurred.

Depreciation, Depletion and Amortization ("DD&A") The 2004 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 2004 compared to the costs incurred for such efforts, and the revisions to Devon's year-end 2003 reserve estimates that, based on prior experience, are likely to be made during 2004.

Given these uncertainties, we expect oil and gas property related DD&A expense for 2004 to be between $2.2 billion and $2.3 billion. Additionally, Devon expects its DD&A expense related to non-oil and gas property fixed assets to total between $120 million and $130 million. Based on these DD&A amounts and the production estimates set forth earlier, Devon expects its consolidated DD&A rate will be between $9.00 per Boe and $9.30 per Boe.

Accretion of Asset Retirement Obligation As a result of the requirements of Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, Devon expects its 2004 accretion of its asset retirement obligation to be between $40 million and $45 million.

General and Administrative Expenses ("G&A") Devon's G&A includes the costs of many different goods and services used in support of its business. These goods and services are subject to general price level increases or decreases. In addition, Devon's G&A varies with its level of activity and the related staffing needs as well as with the amount of professional services required during any given period. Should our needs or the prices of the required goods and services differ significantly from current expectations, actual G&A could vary materially from the estimate. Given these limitations, consolidated G&A in 2004 is expected to be between $305 million and $325 million.

This estimate does not include the potential non-cash effect on G&A caused by changes in the value of investments of deferred compensation plans. Positive returns from these investments increase Devon's G&A, while negative returns decrease G&A.

Reduction of Carrying Value of Oil and Gas Properties Devon follows the full cost method of accounting for its oil and gas properties. Under the full cost method, Devon's net book value of oil and gas properties, less related deferred income taxes and asset retirement obligations (the "costs to be recovered"), may not exceed a calculated "full cost ceiling." The ceiling limitation is the discounted estimated after-tax future net revenues from oil and gas properties plus the cost of properties not subject to amortization. The ceiling is imposed separately by country. In calculating future net revenues, current prices and costs are generally held constant indefinitely. The costs to be recovered are compared to the ceiling on a quarterly basis. If the costs to be recovered exceed the ceiling, the excess 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.

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 cyclical and, on any particular day at the end of a quarter, can be either substantially higher or lower than Devon's long-term price forecast that is a barometer for true fair value. Oil and gas property writedowns that result from applying the full cost ceiling limitation are caused by fluctuations in price. Such writedowns do not indicate reductions to the underlying quantities of reserves and should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves.

Because of the volatile nature of oil and gas prices, it is not possible to predict whether we will incur a full cost writedown in future periods.

Interest Expense Future interest rates, debt outstanding and oil, natural gas and NGL prices have a significant effect on Devon's interest expense. Devon can only marginally influence the prices it will receive in 2004 from sales of oil, natural gas and NGLs and the resulting cash flow. These factors increase the margin of error inherent in estimating future interest expense. Other factors that affect interest expense, such as the amount and timing of capital expenditures, are within Devon's control.

The interest expense in 2004 related to Devon's fixed-rate debt, including net accretion of related discounts, will be approximately $475 million. This fixed-rate debt removes the uncertainty of future interest rates from some, but not all, of Devon's long-term debt. Devon's floating rate debt is discussed in the following paragraphs.

Devon has a 5-year term loan facility due in 2006 that bears interest at floating rates. Devon also has various debt instruments that have been converted to floating rate debt through the use of interest rate swaps. Devon's floating rate debt is as follows:

DEBT INSTRUMENT	FACE VALUE (IN MILLIONS)	FLOATING RATE
5-year term loan facility due in 2006	$ 635	LIBOR plus 100 basis points
4.375% senior notes due in 2007	$ 400	LIBOR plus 40 basis points
10.25% bond due in 2005	$ 236	LIBOR plus 711 basis points
8.05% senior notes due in 2004	$ 125	LIBOR plus 336 basis points
2.75% notes due in 2006	$ 500	LIBOR less 26.8 basis points
7.625% senior notes due in 2005	$ 125	LIBOR plus 237 basis points

Based on Devon's interest rate projections, interest expense on its floating rate debt, including net amortization of premiums, is expected to total between $45 million and $55 million in 2004.

Devon's interest expense totals have historically included payments of facility and agency fees, amortization of debt issuance costs, the effect of interest rate swaps not accounted for as hedges and other miscellaneous items not related to the debt balances outstanding. We expect between $15 million and $20 million of such items to be included in its 2004 interest expense. Also, we expect to capitalize between $25 million and $30 million of interest during 2004.

Based on the information related to interest expense set forth herein and assuming no material changes in Devon's levels of indebtedness or prevailing interest rates, Devon expects its 2004 interest expense will be between $510 million and $520 million.

Effects of Changes in Foreign Currency Rates Devon's Canadian subsidiary has $400 million of fixed-rate senior notes which are denominated in U.S. dollars. Changes in the exchange rate between the U.S. dollar and the Canadian dollar during 2004 will increase or decrease the Canadian dollar equivalent balance of this debt. Such changes in the Canadian dollar equivalent balance of the debt are required to be included in determining net earnings for the period in which the exchange rate changes. Because of the variability of the exchange rate, it is difficult to estimate the effect which will be recorded in 2004. However, based on the December 31, 2003, Canadian-to-U.S. dollar exchange rate of $0.7738 and Devon's forecast 2004 rate of $0.7600, Devon expects to record an expense of approximately $7 million. The actual 2004 effect will depend on the exchange rate as of December 31, 2004.

Other Revenues Devon's other revenues in 2004 are expected to be between $30 million and $35 million.

Income Taxes Devon's financial income tax rate in 2004 will vary materially depending on the actual amount of financial pre-tax earnings. The tax rate for 2004 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 2004's income tax expense regardless of the level of pre-tax earnings that are produced. Given the uncertainty of its pre-tax earnings amount, Devon estimates that its consolidated financial income tax rate in 2004 will be between 25% and 45%. The current income tax rate is expected to be between 20% and 30%. The deferred income tax rate is expected to be between 5% and 15%. Significant changes in estimated capital expenditures, production levels of oil, 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 2004's financial income tax rates.

YEAR 2004 POTENTIAL CAPITAL SOURCES, USES AND LIQUIDITY

Capital Expenditures Though Devon has 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, if any.

Devon's 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 future production, some projects may be accelerated or deferred and, consequently, may increase or decrease total 2004 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 Devon's estimates.

Given the limitations discussed, Devon expects its 2004 capital expenditures for drilling and development efforts, plus related facilities, to total between $2.14 billion and $2.54 billion. These amounts include between $510 million and $550 million for drilling and facilities costs related to reserves classified as proved as of year-end 2003. In addition, these amounts include between $950 million and $1.2 billion for other low risk/reward projects and between $680 million and $760 million for new, higher risk/reward projects. Low risk/reward projects include development drilling that does not offset currently productive units and for which there is not a certainty of continued production from a known productive formation. Higher risk/reward projects include exploratory drilling to find and produce oil or gas in previously untested fault blocks or new reservoirs.

The following table shows expected drilling and facilities expenditures by geographic area.

	UNITED STATES ONSHORE	UNITED STATES OFFSHORE	CANADA	INTERNATIONAL	TOTAL
			(IN MILLIONS)		
Related to Proved Reserves	$270 - $280	$130 - $140	$ 40 - $ 50	$ 70 - $ 80	$ 510 - $ 550
Lower Risk/Reward Projects	$405 - $560	$ 95 - $110	$400 - $500	$ 50 - $ 60	$ 950 - $1,230
Higher Risk/Reward Projects	$ 95 - $105	$235 - $255	$250 - $280	$100 - $120	$ 680 - $ 760
Total	$770 - $945	$460 - $505	$690 - $830	$220 - $260	$2,140 - $2,540

In addition to the above expenditures for drilling and development, Devon expects to spend between $90 million to $100 million on its marketing and midstream assets, which include its oil pipelines, gas processing plants, CO_2 removal facilities and gas transport pipelines. Devon also expects to capitalize between $160 million and $170 million of G&A expenses in accordance with the full cost method of accounting and to capitalize between $25 million and $30 million of interest. Devon also expects to pay between $40 million and $45 million for plugging and abandonment charges and to spend between $90 million and $100 million for other non-oil and gas property fixed assets.

Other Cash Uses Devon's management expects the policy of paying a quarterly common stock dividend to continue. With the February 2004 increase in the quarterly dividend rate to $0.10 per share and 239 million shares of common stock outstanding in January 2004, dividends are expected to approximate $96 million. Also, Devon has $150 million of 6.49% cumulative preferred stock upon which it will pay $10 million of dividends in 2004.

Capital Resources and Liquidity Devon's estimated 2004 cash uses, including its drilling and development activities, are expected to be funded primarily through a combination of working capital and operating cash flow, with the remainder, if any, funded with borrowings from Devon's credit facilities. The amount of operating cash flow to be generated during 2004 is uncertain due to the factors affecting revenues and expenses as previously cited. However, Devon expects its combined capital resources to be more than adequate to fund its anticipated capital expenditures and other cash uses for 2004. As of December 31, 2003, Devon has $800 million available under its $1 billion of credit facilities, net of $200 million of outstanding letters of credit. If significant acquisitions or other unplanned capital requirements arise during the year, Devon could utilize its existing credit facilities 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 Devon's 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 Devon views and manages its ongoing market risk exposures. All of Devon's market risk sensitive instruments were entered into for purposes other than speculative trading.

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

Devon periodically enters into financial hedging activities with respect to a portion of its projected oil and natural gas production through various financial transactions which hedge the future prices received. These transactions include financial price swaps whereby Devon will receive a fixed price for its production and pay a variable market price to the contract counterparty, and costless price collars that set a floor and ceiling price for the hedged production. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. These financial hedging activities are intended to support oil and natural gas prices at targeted levels and to manage Devon's exposure to oil and gas price fluctuations. Devon does not hold or issue derivative instruments for speculative trading purposes.

Devon's total hedged positions on future production as of December 31, 2003, are set forth in the following tables.

Price Swaps Through various price swaps, Devon has fixed the price it will receive on a portion of its oil and natural gas production in 2004 through 2005. The following tables include information on this fixed-price production by area. Where necessary, the gas prices related to these swaps have been adjusted for certain transportation costs that are netted against the price recorded by Devon, and the price has also been adjusted for the Btu content of the gas production that has been hedged.

OIL PRODUCTION

	2004		
AREA	BBLS/DAY	PRICE/BBL	MONTHS OF PRODUCTION
United States Onshore	11,000	$ 27.51	Jan – Dec
United States Offshore	18,000	$ 27.16	Jan – Dec
Canada	15,000	$ 27.53	Jan – Dec
International	20,000	$ 26.03	Jan – Dec

	2005		
AREA	BBLS/DAY	PRICE/BBL	MONTHS OF PRODUCTION
United States Offshore	10,000	$ 27.17	Jan – Dec
Canada	6,000	$ 27.26	Jan – Dec
International	6,000	$ 25.88	Jan – Dec

GAS PRODUCTION

	2004		
AREA	MCF/DAY	PRICE/MCF	MONTHS OF PRODUCTION
United States Onshore	8,435	$ 3.10	Jan – Dec

	2005		
AREA	MCF/DAY	PRICE/MCF	MONTHS OF PRODUCTION
United States Onshore	7,343	$ 2.97	Jan – Dec

Costless Price Collars Devon has also entered into costless price collars that set a floor and ceiling price for a portion of its 2004 and 2005 oil production that otherwise is subject to floating prices. The floor and ceiling prices related to domestic and Canadian oil production are based on the NYMEX price. The floor and ceiling prices related to international oil production are based on the Brent price. If the NYMEX or Brent price is outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. Any such settlements will either increase or decrease Devon's oil revenues for the period. Because Devon's oil volumes are often sold at prices that differ from the NYMEX or Brent price due to differing quality (i.e., sweet crude versus sour crude) and transportation costs from different geographic areas, the floor and ceiling prices of the various collars do not reflect actual limits of Devon's realized prices for the production volumes related to the collars.

Devon has also entered into costless price collars that set a floor and ceiling price for a portion of its 2004 and 2005 natural gas production that otherwise is subject to floating prices. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. Any such settlements will either increase or decrease Devon's gas revenues for the period. Because Devon's gas volumes are often sold at prices that differ from the related regional indices, and due to differing Btu contents of gas produced, the floor and ceiling prices of the various collars do not reflect actual limits of Devon's realized prices for the production volumes related to the collars.

To simplify presentation, Devon's costless collars as of December 31, 2003, have been aggregated in the following tables according to similar floor prices and similar ceiling prices. The floor and ceiling prices shown are weighted averages of the various collars in each aggregated group.

The international oil prices shown in the following tables have been adjusted to a NYMEX-based price, using Devon's estimates of future differentials between NYMEX and the Brent price upon which the collars are based.

The natural gas prices shown in the following tables have been adjusted to a NYMEX-based price, using Devon's estimates of future differentials between NYMEX and the specific regional indices upon which the collars are based. The floor and ceiling prices related to the domestic collars are based on various regional first-of-the-month price indices as published monthly by *Inside FERC*. The floor and ceiling prices related to the Canadian collars are based on the AECO index as published by the *Canadian Gas Price Reporter*.

OIL PRODUCTION

AREA (RANGE OF FLOOR PRICES/CEILING PRICES)	BBLS/DAY	2004 WEIGHTED AVERAGE FLOOR PRICE PER BBL	2004 WEIGHTED AVERAGE CEILING PRICE PER BBL	MONTHS OF PRODUCTION
United States Onshore				
($20.00 - $21.50 / $26.50 - $27.90)	3,000	$ 20.83	$ 27.43	Jan – Dec
($20.00 - $22.00 / $28.35 - $29.75)	6,000	$ 21.42	$ 29.25	Jan – Dec
($22.00 - $22.00 / $30.10 - $30.60)	2,000	$ 22.00	$ 30.35	Jan – Dec
United States Offshore				
($20.00 - $22.00 / $27.55 - $29.75)	6,000	$ 21.42	$ 28.75	Jan – Dec
($22.00 - $22.00 / $30.00 - $31.40)	7,000	$ 22.00	$ 30.74	Jan – Dec
Canada				
($20.00 - $21.50 / $26.50 - $27.70)	3,000	$ 20.50	$ 27.07	Jan – Dec
($20.00 - $22.00 / $28.00 - $29.20)	5,000	$ 21.10	$ 28.69	Jan – Dec
($22.00 - $22.00 / $29.80 - $32.35)	8,000	$ 22.00	$ 31.14	Jan – Dec
International				
($22.31 - $22.31 / $30.11 - $31.51)	27,000	$ 22.31	$ 30.82	Jan – Dec
($22.31 - $22.31 / $31.56 - $32.81)	10,000	$ 22.31	$ 31.96	Jan – Dec

AREA (RANGE OF FLOOR PRICES/CEILING PRICES)	BBLS/DAY	2005 WEIGHTED AVERAGE FLOOR PRICE PER BBL	2005 WEIGHTED AVERAGE CEILING PRICE PER BBL	MONTHS OF PRODUCTION
United States Onshore				
($22.00 - $22.00 / $28.00 - $28.75)	3,000	$ 22.00	$ 28.25	Jan – Dec
United States Offshore				
($22.00 - $22.00 / $27.50 - $29.00)	17,000	$ 22.00	$ 27.62	Jan – Dec
Canada				
($22.00 - $22.00 / $27.50 - $29.10)	15,000	$ 22.00	$ 28.28	Jan – Dec
International				
($22.75 - $22.75 / $28.45 - $29.25)	15,000	$ 22.75	$ 28.86	Jan – Dec

GAS PRODUCTION

AREA (RANGE OF FLOOR PRICES/CEILING PRICES)	MMBTU/DAY	2004 WEIGHTED AVERAGE FLOOR PRICE PER MMBTU	2004 WEIGHTED AVERAGE CEILING PRICE PER MMBTU	MONTHS OF PRODUCTION
United States Onshore				
($3.32 - $4.22 / $4.97 - $6.37)	110,000	$ 3.77	$ 5.91	Jan – Dec
($3.32 - $4.47 / $6.47 - $7.35)	215,000	$ 4.10	$ 6.87	Jan – Dec
($3.32 - $4.00 / $7.45 - $7.85)	45,000	$ 3.54	$ 7.62	Jan – Dec
($3.50 - $4.07 / $8.02 - $8.86)	100,000	$ 3.61	$ 8.37	Jan – Dec
($4.00 - $4.15 / $7.00 - $7.00)	40,000	$ 4.06	$ 7.00	Jan – Jun
($4.02 - $4.03 / $6.98 - $6.99)	50,000	$ 4.03	$ 6.99	Jul – Dec
United States Offshore				
($3.25 - $3.25 / $7.00 - $7.00)	10,000	$ 3.25	$ 7.00	Jan – Dec
($3.50 - $3.50 / $7.40 - $7.90)	50,000	$ 3.50	$ 7.74	Jan – Dec
($4.00 - $4.00 / $7.43 - $8.80)	130,000	$ 4.00	$ 7.71	Jan – Dec
($4.00 - $4.12 / $7.00 - $7.00)	60,000	$ 4.07	$ 7.00	Jan – Jun
($4.00 - $4.00 / $7.00 - $7.00)	50,000	$ 4.00	$ 7.00	Jul – Dec
Canada				
($4.10 - $4.21 / $6.46 - $7.07)	60,000	$ 4.18	$ 6.76	Jan – Dec
($4.06 - $4.59 / $7.17 - $7.94)	140,000	$ 4.29	$ 7.51	Jan – Dec
($3.98 - $4.13 / $8.43 - $8.75)	60,000	$ 4.04	$ 8.63	Jan – Dec
($3.96 - $4.25 / $9.14 - $9.64)	70,000	$ 4.06	$ 9.33	Jan – Dec
($3.96 - $4.05 / $9.91 - $10.54)	25,000	$ 4.02	$ 10.37	Jan – Dec
($4.60 - $4.85 / $6.53 - $6.53)	90,000	$ 4.75	$ 6.53	Jan – Jun
($4.60 - $4.86 / $6.53 - $6.71)	70,000	$ 4.73	$ 6.61	Jul – Dec

AREA (RANGE OF FLOOR PRICES/CEILING PRICES)	MMBTU/DAY	2005 WEIGHTED AVERAGE FLOOR PRICE PER MMBTU	2005 WEIGHTED AVERAGE CEILING PRICE PER MMBTU	MONTHS OF PRODUCTION
United States Onshore				
($3.97 - $4.05 / $6.94 - $6.99)	40,000	$ 4.01	$ 6.97	Jan – Jun
United States Offshore				
($3.50 - $3.50 / $7.50 - $7.50)	40,000	$ 3.50	$ 7.50	Jan – Dec
($4.04 - $4.17 / $7.00 - $7.00)	70,000	$ 4.09	$ 7.00	Jan – Jun

Devon uses a sensitivity analysis technique to evaluate the hypothetical effect that changes in the market value of oil and gas may have on the fair value of its commodity hedging instruments. At December 31, 2003, a 10% increase in the underlying commodities prices would have increased the net liabilities recorded for Devon's commodity hedging instruments by $253 million.

Fixed-Price Physical Delivery Contracts In addition to the commodity hedging instruments described above, Devon also manages its exposure to oil and gas price risks by periodically entering into fixed-price contracts.

Devon has fixed-price physical delivery contracts for the years 2004 through 2011 covering Canadian natural gas production ranging from 8 Bcf to 16 Bcf per year. From 2012 through 2016, Devon also has Canadian gas volumes subject to fixed-price contracts, but the yearly volumes are less than 1 Bcf.

Interest Rate Risk At December 31, 2003, Devon had debt outstanding of $8.9 billion. Of this amount, $6.9 billion, or 77%, bears interest at fixed rates averaging 7.0%. Devon also has a floating-to-fixed interest rate swap in which Devon will record a fixed rate of 6.4% on a notional amount of $97 million in 2003 through 2006 and 6.3% on a notional amount of $30 million in 2007.

The remaining $2.0 billion of debt outstanding bears interest at floating rates. Included in the floating-rate debt is debt with floating rates and fixed-rate debt, which has been converted to floating-rate debt through interest rate swaps. The terms of Devon's various floating-rate debt facilities (revolving credit facilities and term-loan credit facility) allow interest rates to be fixed at Devon's option for periods of between seven to 180 days. A 10% increase in short-term interest rates on the floating-rate debt facilities outstanding as of December 31, 2003, would equal approximately 22 basis points. Such an increase in interest rates would increase Devon's 2004 interest expense by approximately $1 million assuming borrowed amounts remain outstanding for all of 2004. Following is a table summarizing the fixed-to-floating interest rate swaps with the related debt instrument and notional amounts.

DEBT INSTRUMENT	NOTIONAL AMOUNT (IN MILLIONS)	FLOATING RATE
4.375% senior notes due in 2007	$ 400	LIBOR plus 40 basis points
10.25% bond due in 2005	$ 235	LIBOR plus 711 basis points
8.05% senior notes due in 2004	$ 125	LIBOR plus 336 basis points
2.75% notes due in 2006	$ 500	LIBOR less 26.8 basis points
7.625% senior notes due in 2005	$ 125	LIBOR plus 237 basis points

Devon uses a sensitivity analysis technique to evaluate the hypothetical effect that changes in interest rates may have on the fair value of its interest rate swap instruments. At December 31, 2003, a 10% increase in the underlying interest rates would have decreased the fair value of Devon's interest rate swaps by $8 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 Devon's net assets, net earnings and cash flows from its 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.

Devon's Canadian subsidiary, Devon Canada, has $400 million of fixed-rate long-term debt that is denominated in U.S. dollars. Changes in the currency conversion rate between the Canadian and U.S. dollars between the beginning and end of a reporting period increase or decrease the expected amount of Canadian dollars required to repay the notes. The amount of such increase or decrease is required to be included in determining net earnings for the period in which the exchange rate changes. A 10% decrease in the Canadian-to-U.S. dollar exchange rate would cause Devon to record a charge of approximately $40 million in 2004. The $400 million becomes due in March 2011. Until then, the gains or losses caused by the exchange rate fluctuations have no effect on cash flow.

Management's Responsibility for Financial Statements

Devon Energy Corporation's management takes responsibility for the accompanying consolidated financial statements which have been prepared in conformity with accounting principles generally accepted in the United States of America. They are based on our best estimate and judgment. Financial information elsewhere in this annual report is consistent with the data presented in these statements.

In order to carry out our responsibility concerning the integrity and objectivity of published financial data, we maintain an accounting system and related internal controls. We believe the system is sufficient in all material respects to provide reasonable assurance that financial records are reliable for preparing financial statements and that assets are safeguarded from loss or unauthorized use.

Our independent auditing firm, KPMG LLP, provides objective consideration of Devon Energy management's discharge of its responsibilities as it relates to the fairness of reported operating results and the financial position of the company. This firm obtains and maintains an understanding of our accounting and financial controls to the extent necessary to audit our financial statements and employs all testing and verification procedures it considers necessary to arrive at an opinion on the fairness of financial statements.

The board of directors pursues its responsibilities for the accompanying consolidated financial statements through its Audit Committee. The committee meets periodically with management and the independent auditors to assure that they are carrying out their responsibilities. The independent auditors have full and free access to the committee members and meet with them to discuss auditing and financial reporting matters.

DEVON ENERGY CORPORATION EXECUTIVE COMMITTEE

J. Larry Nichols
Chairman & CEO

John Richels
President

Brian J. Jennings
Senior Vice President & CFO

Duke R. Ligon
Senior Vice President

Marian J. Moon
Senior Vice President

Darryl G. Smette
Senior Vice President

Independent Auditors' Report

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, 2003, and 2002 and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss) and cash flows for each of the years in the three-year period ended December 31, 2003. 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 auditing standards generally accepted in the United States of America. 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, 2003, and 2002, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As described in Note 1 to the consolidated financial statements, as of January 1, 2001, the company changed its method of accounting for derivative instruments and hedging activities; effective July 1, 2001, adopted the provisions of Statement of Financial Accounting Standards ("SFAS") No. 141, *Business Combinations* and certain provisions of SFAS No. 142, *Goodwill and Other Intangible Assets*; effective January 1, 2002, adopted the remaining provisions of SFAS No. 142; and effective January 1, 2003, adopted SFAS No. 143, *Asset Retirement Obligations*.

KPMG LLP

Oklahoma City, Oklahoma
February 4, 2004

Consolidated Balance Sheets

DECEMBER 31, (IN MILLIONS, EXCEPT SHARE DATA)	2003	2002
Assets		
Current assets:		
Cash and cash equivalents	$ 1,273	292
Accounts receivable	946	639
Inventories	72	26
Fair value of financial instruments	13	4
Income taxes receivable	11	56
Assets of discontinued operations	—	7
Investments and other current assets	49	40
Total current assets	2,364	1,064
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($3,336 and $2,289 excluded from amortization in 2003 and 2002, respectively)	28,546	18,786
Less accumulated depreciation, depletion and amortization	10,212	7,934
	18,334	10,852
Investment in ChevronTexaco Corporation common stock, at fair value	613	472
Fair value of financial instruments	14	1
Goodwill	5,477	3,555
Other assets	360	281
Total assets	$ 27,162	16,225
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable:		
Trade	$ 859	376
Revenues and royalties due to others	315	261
Income taxes payable	15	9
Current portion of long-term debt	338	—
Deferred revenue	56	—
Accrued interest payable	130	119
Merger related expenses payable	21	12
Fair value of financial instruments	153	151
Current portion of asset retirement obligation	42	—
Accrued expenses and other current liabilities	142	114
Total current liabilities	2,071	1,042
Other liabilities	349	323
Asset retirement obligation, long-term	629	—
Debentures exchangeable into shares of ChevronTexaco Corporation common stock	677	662
Other long-term debt	7,903	6,900
Preferred stock of a subsidiary	55	—
Fair value of financial instruments	52	18
Deferred income taxes	4,370	2,627
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 $.10 par value Authorized 800,000,000 shares; issued 239,767,000 in 2003 and 160,461,000 in 2002	24	16
Additional paid-in capital	9,066	5,178
Retained earnings (accumulated deficit)	1,614	(84)
Accumulated other comprehensive income (loss)	569	(267)
Deferred compensation and other	(32)	(3)
Treasury stock, at cost: 3,677,000 shares in 2003 and 3,704,000 shares in 2002	(186)	(188)
Total stockholders' equity	11,056	4,653
Commitments and contingencies (Note 14)		
Total liabilities and stockholders' equity	$ 27,162	16,225

See accompanying notes to consolidated financial statements

Consolidated Statements of Operations

YEAR ENDED DECEMBER 31, (IN MILLIONS, EXCEPT PER SHARE AMOUNTS)		2003	2002	2001
Revenues				
Oil sales	$	1,588	909	784
Gas sales		3,897	2,133	1,878
NGL sales		407	275	131
Marketing and midstream revenues		1,460	999	71
Total revenues		7,352	4,316	2,864
Operating Costs and Expenses				
Lease operating expenses		871	621	467
Transportation costs		207	154	83
Production taxes		204	111	116
Marketing and midstream operating costs and expenses		1,174	808	47
Depreciation, depletion and amortization of property and equipment		1,793	1,211	831
Accretion of asset retirement obligation		36	—	—
Amortization of goodwill		—	—	34
General and administrative expenses		307	219	114
Expenses related to mergers		7	—	1
Reduction of carrying value of oil and gas properties		111	651	979
Total operating costs and expenses		4,710	3,775	2,672
Earnings from operations		2,642	541	192
Other Income (Expenses)				
Interest expense		(502)	(533)	(220)
Dividends on subsidiary's preferred stock		(2)	—	—
Effects of changes in foreign currency exchange rates		69	1	(11)
Change in fair value of financial instruments		1	28	(2)
Impairment of ChevronTexaco Corporation common stock		—	(205)	—
Other income		37	34	69
Net other expenses		(397)	(675)	(164)
Earnings (loss) from continuing operations before income taxes and cumulative effect of change in accounting principle		2,245	(134)	28
Income Tax Expense (Benefit)				
Current		193	23	48
Deferred		321	(216)	(43)
Total income tax expense (benefit)		514	(193)	5
Earnings from continuing operations before cumulative effect of change in accounting principle		1,731	59	23
Discontinued Operations				
Results of discontinued operations before income taxes (including net gain on disposal of $31 million in 2002)		—	54	56
Income tax expense		—	9	25
Net results of discontinued operations		—	45	31
Earnings before cumulative effect of change in accounting principle		1,731	104	54
Cumulative effect of change in accounting principle, net of tax		16	—	49
Net earnings		1,747	104	103
Preferred stock dividends		10	10	10
Net earnings applicable to common shareholders	$	1,737	94	93
Basic net earnings per share:				
Earnings from continuing operations	$	8.24	0.32	0.09
Net results of discontinued operations		—	0.29	0.25
Cumulative effect of change in accounting principle, net of tax		0.08	—	0.39
Net earnings	$	8.32	0.61	0.73
Diluted net earnings per share:				
Earnings from continuing operations	$	8.00	0.32	0.09
Net results of discontinued operations		—	0.29	0.25
Cumulative effect of change in accounting principle, net of tax		0.07	—	0.38
Net earnings	$	8.07	0.61	0.72
Weighted average common shares outstanding:				
Basic		209	155	128
Diluted		217	156	130

See accompanying notes to consolidated financial statements

Consolidated Statements of Stockholders' Equity and Comprehensive Income (Loss)

(IN MILLIONS)		PREFERRED STOCK	COMMON STOCK	ADDITIONAL PAID-IN CAPITAL	RETAINED EARNINGS (ACCUMULATED DEFICIT)	ACCUMULATED OTHER COMPRE-HENSIVE INCOME (LOSS)	DEFERRED COMPEN-SATION AND OTHER	TREASURY STOCK	TOTAL STOCK-HOLDERS' EQUITY
Balance as of December 31, 2000	$	1	13	3,564	(215)	(85)	(1)	—	3,277
Comprehensive income:									
Net earnings		—	—	—	103	—	—	—	103
Other comprehensive income (loss), net of tax:									
Foreign currency translation adjustments		—	—	—	—	(107)	—	—	(107)
Cumulative effect of change in accounting principle		—	—	—	—	(37)	—	—	(37)
Reclassification adjustment for derivative gains reclassified into oil and gas sales		—	—	—	—	(20)	—	—	(20)
Change in fair value of financial instruments		—	—	—	—	216	—	—	216
Minimum pension liability adjustment		—	—	—	—	(17)	—	—	(17)
Unrealized gain on marketable securities		—	—	—	—	22	—	—	22
Other comprehensive income									57
Comprehensive income									160
Stock issued		—	—	48	—	—	—	—	48
Stock repurchased		—	—	(14)	—	—	—	(190)	(204)
Tax benefit related to employee stock options		—	—	12	—	—	—	—	12
Dividends on common stock		—	—	—	(25)	—	—	—	(25)
Dividends on preferred stock		—	—	—	(10)	—	—	—	(10)
Amortization of restricted stock awards		—	—	—	—	—	1	—	1
Balance as of December 31, 2001		1	13	3,610	(147)	(28)	—	(190)	3,259
Comprehensive loss:									
Net earnings		—	—	—	104	—	—	—	104
Other comprehensive income (loss), net of tax:									
Foreign currency translation adjustments		—	—	—	—	46	—	—	46
Reclassification adjustment for derivative gains reclassified into oil and gas sales		—	—	—	—	(39)	—	—	(39)
Change in fair value of financial instruments		—	—	—	—	(217)	—	—	(217)
Minimum pension liability adjustment		—	—	—	—	(54)	—	—	(54)
Unrealized loss on marketable securities		—	—	—	—	(103)	—	—	(103)
Impairment of marketable securities		—	—	—	—	128	—	—	128
Other comprehensive loss									(239)
Comprehensive loss									(135)
Stock issued		—	3	1,559	—	—	—	2	1,564
Tax benefit related to employee stock options		—	—	6	—	—	—	—	6
Dividends on common stock		—	—	—	(31)	—	—	—	(31)
Dividends on preferred stock		—	—	—	(10)	—	—	—	(10)
Grant of restricted stock awards		—	—	3	—	—	(3)	—	—
Balance as of December 31, 2002		1	16	5,178	(84)	(267)	(3)	(188)	4,653
Comprehensive income:									
Net earnings		—	—	—	1,747	—	—	—	1,747
Other comprehensive income (loss), net of tax:									
Foreign currency translation adjustments		—	—	—	—	766	—	—	766
Reclassification adjustment for derivative losses reclassified into oil and gas sales		—	—	—	—	198	—	—	198
Change in fair value of financial instruments		—	—	—	—	(236)	—	—	(236)
Minimum pension liability adjustment		—	—	—	—	19	—	—	19
Unrealized gain on marketable securities		—	—	—	—	89	—	—	89
Other comprehensive income									836
Comprehensive income									2,583
Stock issued		—	7	3,824	—	—	—	2	3,833
Tax benefit related to employee stock options		—	—	31	—	—	—	—	31
Dividends on common stock		—	—	—	(39)	—	—	—	(39)
Dividends on preferred stock		—	—	—	(10)	—	—	—	(10)
Grant of restricted stock awards		—	1	33	—	—	(34)	—	—
Amortization of restricted stock awards		—	—	—	—	—	2	—	2
Other		—	—	—	—	—	3	—	3
Balance as of December 31, 2003	$	1	24	9,066	1,614	569	(32)	(186)	11,056

See accompanying notes to consolidated financial statements

Consolidated Statements of Cash Flows

YEAR ENDED DECEMBER 31, (IN MILLIONS)	2003	2002	2001
Cash Flows From Operating Activities			
Earnings from continuing operations	$ 1,731	59	23
Adjustments to reconcile earnings from continuing operations to net cash provided by operating activities:			
Depreciation, depletion and amortization of property and equipment	1,793	1,211	831
Amortization of goodwill	—	—	34
Accretion of asset retirement obligation	36	—	—
Accretion of discounts on long-term debt, net	19	33	26
Effects of changes in foreign currency exchange rates	(69)	(1)	11
Change in fair value of financial instruments	(1)	(28)	2
Reduction of carrying value of oil and gas properties	111	651	979
Impairment of ChevronTexaco Corporation common stock	—	205	—
Operating cash flows from discontinued operations	—	28	134
Loss (gain) on sale of assets	7	(2)	2
Deferred income tax expense (benefit)	321	(216)	(43)
Other	(48)	(9)	(3)
Changes in assets and liabilities, net of effects of acquisitions of businesses:			
(Increase) decrease in:			
Accounts receivable	(164)	(80)	203
Inventories	(8)	10	12
Investments and other current assets	(26)	12	(76)
Increase (decrease) in:			
Accounts payable	42	(74)	37
Income taxes payable	62	21	(129)
Accrued interest and expenses	39	36	(46)
Deferred revenue	(41)	(46)	(63)
Long-term other liabilities	(36)	(56)	(24)
Net cash provided by operating activities	3,768	1,754	1,910
Cash Flows From Investing Activities			
Proceeds from sale of property and equipment	179	1,067	41
Capital expenditures, including acquisitions of businesses	(2,587)	(3,426)	(5,235)
Discontinued operations (including net proceeds from sale of $336 million in 2002)	—	316	(91)
Other	(24)	(3)	—
Net cash used in investing activities	(2,432)	(2,046)	(5,285)
Cash Flows From Financing Activities			
Proceeds from borrowings of long-term debt, net of issuance costs	597	6,067	6,199
Principal payments on long-term debt	(1,118)	(5,657)	(2,638)
Issuance of common stock, net of issuance costs	155	32	48
Repurchase of common stock	—	—	(204)
Dividends paid on common stock	(39)	(31)	(25)
Dividends paid on preferred stock	(10)	(10)	(10)
Increase in long-term other liabilities	1	—	—
Net cash (used in) provided by financing activities	(414)	401	3,370
Effect of exchange rate changes on cash	59	—	(6)
Net increase (decrease) in cash and cash equivalents	981	109	(11)
Cash and cash equivalents at beginning of year	292	183	194
Cash and cash equivalents at end of year	$ 1,273	292	183

See accompanying notes to consolidated financial statements

Notes To Consolidated Financial Statements

DECEMBER 31, 2003, 2002 AND 2001

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 domestically are concentrated in four geographic areas:

- 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 Mid-Continent area of the central and southern United States; and
- the Gulf Coast, which includes properties located primarily in the onshore south Texas and south Louisiana areas and offshore in the Gulf of Mexico.

Devon's Canadian activities are located primarily in the Western Canadian Sedimentary Basin, and Devon's international activities—outside of North America—are located primarily in Azerbaijan, China, Egypt and areas in West Africa, including Equatorial Guinea, Gabon and Cote d'Ivoire.

Devon also has marketing and midstream operations which are responsible for marketing natural gas, crude oil and NGLs and the construction and operation of 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 wholly owned 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. Significant items subject to such estimates and assumptions include the carrying value of oil and gas properties, goodwill impairment assessment, asset retirement obligations, deferred income taxes, valuation of derivative instruments and obligations related to employee benefits. Actual amounts could differ from those estimates.

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.

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.

Net capitalized costs are limited to the estimated future net revenues, discounted at 10% per annum, from proved oil, natural gas and natural gas liquids reserves plus the cost of properties not subject to amortization. Such limitations are imposed separately on a country-by-country basis and are tested quarterly. 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. 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. 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.

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

In 2003, the Securities Exchange Commission ("SEC") inquired of the Financial Accounting Standards Board regarding the application of certain provisions of SFAS No. 141, *Business Combinations*, ("SFAS No. 141") and SFAS No. 142, *Goodwill and Other Intangible Assets,* ("SFAS No. 142") to oil and gas companies. SFAS Nos. 141 and 142 became effective for transactions subsequent to June 30, 2001. SFAS No. 141 requires that all business combinations initiated after June 30, 2001, be accounted for using the purchase method and that acquired intangible assets be disaggregated and reported separately from goodwill. Specifically, the SEC's inquiry is based on whether costs of contract-based drilling and mineral use rights ("mineral rights") should be recorded and disclosed as intangible assets under the guidance in SFAS Nos. 141 and 142. The current practice for Devon and the industry is to present oil and gas related assets, including mineral rights, as property and equipment (tangible assets) on the balance sheet. Since June 30, 2001, Devon has entered into business combinations with Anderson Exploration, Ltd., Mitchell Energy & Development Corp., and Ocean Energy, Inc. with an aggregate accounting purchase price of $18.2 billion. The majority of the purchase price has been allocated to oil and gas property.

An Emerging Issues Task Force Working Group ("EITF") has been created to research the accounting and disclosure treatment of mineral rights for oil and gas companies. As a result, the EITF has added Issue No. 03-O, "Whether Mineral Rights are Tangible or Intangible Assets," and Issue No. 03-S, "Application of FASB Statement No. 142, Goodwill and Other Intangible Assets, to Oil and Gas Companies." Currently, Devon does not believe that generally accepted accounting principles require the classification of mineral rights as intangible assets and continues to classify these assets as oil and gas properties. However, the decisions of the EITF may affect how Devon classifies these assets in the future. If the EITF ultimately determines that SFAS Nos. 141 and 142 require oil and gas companies to classify mineral rights as separate intangible assets, the amounts included in oil and gas properties on the balance sheet that would be reclassified are not expected to exceed the following amounts:

	DECEMBER 31, 2003	DECEMBER 31, 2002
	(IN MILLIONS)	
Intangible proved drilling and mineral rights, net of accumulated DD&A	$ 7,156	3,057
Intangible unproved drilling and mineral rights	2,678	1,777
Total intangible drilling and mineral rights	$ 9,834	4,834

Amounts to be reclassified would be impacted by the provisions of the EITF consensus. The ultimate reclassification amount could be materially different than the amounts above as numerous decisions that could be included in the consensus would impact the composition and amortization of the intangible assets, if any.

Devon believes that cash flows and results of operations would not be affected since such intangible assets would likely continue to be depleted and assessed for impairment in accordance with Devon's accounting policies as prescribed under the full cost method of accounting for oil and gas properties. Further, Devon does not believe the classification of the mineral rights as intangible assets would affect compliance with covenants under its debt agreements.

Effective January 1, 2003, Devon adopted Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations* ("SFAS No. 143") using a cumulative effect approach to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depreciation. SFAS No. 143 requires liability recognition for retirement obligations associated with tangible long-lived assets, such as producing well sites, offshore production platforms, and natural gas processing plants. The obligations included within the scope of SFAS No. 143 are those for which a company faces a legal obligation. The initial measurement of the asset retirement obligation is to record a separate liability at its fair value with an offsetting asset retirement cost recorded as an increase to the related property and equipment on the consolidated balance sheet. The asset retirement cost is depreciated using a systematic and rational method similar to that used for the associated property and equipment.

Devon previously estimated costs of dismantlement, removal, site reclamation and other similar activities in the total costs that are subject to depreciation, depletion, and amortization. However, Devon did not record a separate asset or liability for such amounts. Upon adoption, Devon recorded a cumulative-effect-type adjustment for an increase to net earnings of $16 million net of deferred taxes of $10 million. Additionally, Devon established an asset retirement obligation of $453 million, an increase to property and equipment of $400 million and a decrease in accumulated DD&A of $79 million.

Following is a reconciliation of reported net income and the related earnings per share amounts assuming the provisions of SFAS No. 143 had been adopted as of January 1, 2001.

		YEAR ENDED DECEMBER 31,		
		2003	2002	2001
		(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)		
Net earnings applicable to common stockholders, as reported	$	1,737	94	93
Less cumulative effect of change in accounting principle		(16)	—	—
Net change in depreciation, depletion and amortization of property and equipment due to adoption of SFAS No. 143		—	16	30
Less accretion of asset retirement obligation		—	(25)	(15)
Deferred taxes		—	4	(6)
Effect on net earnings		(16)	(5)	9
Net earnings applicable to common stockholders, as adjusted	$	1,721	89	102
Basic earnings per share:				
Net earnings applicable to common stockholders, as reported	$	8.32	0.61	0.73
Effect on net earnings		(0.08)	(0.03)	0.07
Net earnings applicable to common stockholders, as adjusted	$	8.24	0.58	0.80
Diluted earnings per share:				
Net earnings applicable to common stockholders, as reported	$	8.07	0.61	0.72
Effect on net earnings		(0.07)	(0.03)	0.07
Net earnings applicable to common stockholders, as adjusted	$	8.00	0.58	0.79

Following is a summary of the asset retirement obligation, assuming the provisions of SFAS No. 143 had been adopted as of January 1, 2001.

		(IN MILLIONS)
Asset retirement obligation as of:		
January 1, 2001	$	244
December 31, 2001	$	397
December 31, 2002	$	453

Marketable Securities and Other Investments

Devon reports investments in debt and equity and other short-term securities at fair value, except for debt securities in which management has the ability and intent to hold until maturity. Devon's only significant investment security is the investment in approximately 7.1 million shares of ChevronTexaco Corporation ("ChevronTexaco") 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 ChevronTexaco common stock is recognized in other comprehensive income (loss) 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. Effective July 1, 2001, Devon adopted the provisions of SFAS No. 141, *Business Combinations*, and certain provisions of SFAS No. 142, *Goodwill and Other Intangible Assets*. Effective January 1, 2002, Devon adopted the remaining provisions of SFAS No. 142. Goodwill and intangible assets with indefinite useful lives are not amortized but are instead tested for impairment at least annually. As of January 1, 2002, Devon had unamortized goodwill in the amount of $2.2 billion, which was subject to the transitional goodwill impairment assessment provisions of SFAS No. 142. During 2002, goodwill increased to $3.6 billion at December 31, 2002, due primarily to the January 2002 Mitchell merger. As a result of the April 2003 Ocean merger and the effects of changes in the Canadian-to-U.S. dollar foreign exchange rates, goodwill increased $1.5 billion and $0.4 billion, respectively, to $5.5 billion at the end of 2003. Devon performed its transitional impairment assessment of goodwill as of January 1, 2002, and its annual assessments of goodwill in the fourth quarter of 2003 and 2002. Based on these assessments, no impairment of goodwill was required.

Following is a reconciliation of reported net income and the related earnings per share amounts assuming the provisions of SFAS No. 142 had been adopted as of January 1, 2001.

		YEAR ENDED DECEMBER 31, 2003	2002	2001
		(IN MILLIONS, EXCEPT PER SHARE DATA)		
Net earnings applicable to common shareholders, as reported	$	1,737	94	93
Add back amortization of goodwill		—	—	34
Net earnings applicable to common shareholders, as adjusted	$	1,737	94	127
Basic earnings per share:				
Net earnings applicable to common shareholders, as reported	$	8.32	0.61	0.73
Amortization of goodwill		—	—	0.26
Net earnings applicable to common shareholders, as adjusted	$	8.32	0.61	0.99
Diluted earnings per share:				
Net earnings applicable to common shareholders, as reported	$	8.07	0.61	0.72
Amortization of goodwill		—	—	0.26
Net earnings applicable to common shareholders, as adjusted	$	8.07	0.61	0.98

Revenue Recognition and Gas Balancing

Oil, gas and NGL revenues are recognized when the products are sold. During the course of normal operations, Devon and other joint interest owners of natural gas reservoirs will take more or less than their respective ownership share of the natural gas volumes produced. These volumetric imbalances are monitored over the lives of the wells' production capability. 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.

Devon follows the sales method of accounting for gas production imbalances. A liability is recorded when Devon's excess takes of natural gas volumes exceed its estimated remaining recoverable reserves. No receivables are recorded for those wells where Devon has taken less than its ownership share of gas production.

Marketing and midstream revenues are recorded on the sales method at the time products are sold or services are provided to third parties. Revenues and expenses attributable to Devon's 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.

Major Purchasers

No purchaser accounted for over 10% of revenues in 2003 and 2002. In 2001, Enron Capital and Trade Resource Corporation accounted for 16% of Devon's combined oil, gas and natural gas liquids sales.

On December 2, 2001, Enron Corp. and certain of its subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code. Prior to this date, Devon had terminated substantially all of its agreements to sell oil, gas or NGLs to Enron related entities. Devon incurred $3 million of losses in 2001 for sales to Enron related subsidiaries which were not collected prior to the bankruptcy filing.

Hedging Activities

Devon enters into oil and gas financial instruments to manage its 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 effects of interest rate fluctuations on interest expense for variable-rate debt instruments or the debt fair values for fixed-rate debt.

In accordance with the transition provisions of SFAS No. 133, *Accounting for Derivative Instruments and Certain Hedging Activities*, ("SFAS No. 133") Devon recorded a net-of-tax cumulative-effect-type adjustment of $37 million loss in accumulated other comprehensive income (loss) ("AOCI") to recognize the fair value of all derivatives that were designated as cash-flow hedging instruments during 2001. Additionally, Devon recorded a net-of-tax cumulative-effect-type adjustment to net earnings of $49 million gain ($0.39 per basic share and $0.38 per diluted share) related to the fair value of derivative instruments that did not qualify as hedges. This gain related principally to the option embedded in Devon's debentures that are exchangeable into shares of ChevronTexaco common stock.

All derivatives are recognized as fair value of financial instruments on the consolidated balance sheets at their fair value. A substantial portion of Devon's derivatives consists of contracts that hedge the price of future oil and natural gas production. These derivative contracts are cash flow hedges that qualify for hedge accounting treatment under SFAS No. 133. Therefore, while fair values of such hedging instruments must be estimated as of the end of each reporting period, the changes in the fair values are not included in Devon's consolidated results of operations. Instead, the changes in fair value of these hedging instruments, net of tax, are recorded directly to stockholders' equity until the hedged oil or natural gas quantities are produced. To qualify for hedge accounting treatment, Devon designates its cash flow hedge instruments as such on the date the derivative contract is entered into or the date of a business combination which includes cash flow hedge instruments. Additionally, Devon documents all relationships between hedging instruments and hedged items, as well as its risk-management objective and strategy for undertaking various hedge transactions. Devon also assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. If Devon fails to meet the requirements for using hedge accounting treatment, the changes in fair value of these hedging instruments would not be recorded directly to equity but in the consolidated results of operations. During 2003, 2002 and 2001, there were no gains or losses reclassified into earnings as a result of the discontinuance of hedge accounting treatment for any of Devon's derivatives.

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 only enter into derivative contracts 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 or interest rates. 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. Devon's commodity costless price collars and price swaps have been designated as cash flow hedges. Changes in the fair value of these derivatives are reported on the balance sheet in AOCI. These amounts are reclassified to oil and gas sales when the forecasted transaction takes place.

During 2003, 2002 and 2001, Devon recorded in its statement of operations a gain of $1 million, a gain of $28 million and a loss of $2 million, respectively, for the change in the fair value of derivative instruments that do not qualify for hedge accounting treatment, as well as the ineffectiveness of derivatives that do qualify as hedges.

As of December 31, 2003, $150 million of net deferred losses on derivative instruments accumulated in AOCI are expected to be reclassified to earnings during the next 12 months assuming no change in the December 31, 2003, commodity prices. Transactions and events expected to occur over the next 12 months that will necessitate reclassifying these derivatives' losses to earnings are primarily the production and sale of oil and gas which includes the production hedged under the various derivative instruments. Presently, the maximum term over which Devon has hedged exposures to the variability of cash flows for commodity price risk is 24 months.

Stock Options

Devon applies the intrinsic value-based method of accounting prescribed by Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations, in accounting for its fixed plan stock options. As such, compensation expense is recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price. SFAS No. 123, *Accounting for Stock-Based Compensation*, established accounting and disclosure requirements using a fair value-based method of accounting for stock-based employee compensation plans. As allowed by SFAS No. 123, Devon has elected to continue to apply the intrinsic value-based method of accounting described above and has adopted the disclosure requirements of SFAS No. 123.

Had Devon elected the fair value provisions of SFAS No. 123 and recognized compensation expense over the vesting period based on the fair value of the stock options granted as of their grant date, Devon's 2003, 2002 and 2001 pro forma net earnings and pro forma net earnings per share would have differed from the amounts actually reported as shown in the following table.

		YEAR ENDED DECEMBER 31,		
		2003	2002	2001
		(IN MILLIONS, EXCEPT PER SHARE DATA)		
Net earnings available to common shareholders, as reported	$	1,737	94	93
Add stock-based employee compensation expense included in reported net earnings, net of related tax expense		2	1	1
Deduct total stock-based employee compensation expense determined under fair value based method for all awards (see Note 11), net of related tax expense		(23)	(17)	(15)
Net earnings available to common shareholders, pro forma	$	1,716	78	79
Net earnings per share available to common shareholders:				
As reported:				
Basic	$	8.32	0.61	0.73
Diluted	$	8.07	0.61	0.72
Pro forma:				
Basic	$	8.22	0.51	0.62
Diluted	$	7.98	0.50	0.61

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. U.S. deferred income taxes have not been provided on undistributed earnings of foreign operations which are being permanently reinvested.

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 reflects the potential dilution that could occur if Devon's dilutive outstanding stock options were exercised (calculated using the treasury stock method), if the preferred stock of a subsidiary were converted to common stock and if Devon's zero coupon convertible senior debentures were converted to common stock.

The following table reconciles the net earnings and common shares outstanding used in the calculations of basic and diluted earnings per share for 2003, 2002 and 2001.

	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, 2003			
Basic earnings per share	$ 1,737	209	$ 8.32
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	—	3	
Dilutive effect of potential common shares issuable upon conversion of preferred stock of subsidiary acquired in 2003 merger	2	1	
Dilutive effect of potential common shares issuable upon conversion of senior convertible debentures (the increase in net earnings is net of income tax expense of $6 million)	9	4	
Diluted earnings per share	$ 1,748	217	$ 8.07
Year Ended December 31, 2002			
Basic earnings per share	$ 94	155	$ 0.61
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	—	1	
Diluted earnings per share	$ 94	156	$ 0.61
Year Ended December 31, 2001			
Basic earnings per share	$ 93	128	$ 0.73
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	—	2	
Diluted earnings per share	$ 93	130	$ 0.72

The senior convertible debentures included in the 2003 dilution calculations were not included in the 2002 and 2001 dilution calculations because the inclusion was anti-dilutive.

Certain options to purchase shares of Devon's common stock have been excluded from the dilution calculations because the options' exercise price exceeded the average market price of Devon's common stock during the applicable year. The following information relates to these options.

	2003	2002	2001
Options excluded from dilution calculation (in millions)	5	5	3
Range of exercise prices	$ 49.91 – $89.66	$ 45.49 – $89.66	$ 48.13 – $89.66
Weighted average exercise price	$ 56.10	$ 50.85	$ 56.11

The excluded options for 2003 expire between January 12, 2004, and September 9, 2012.

Foreign Currency Translation Adjustments

The assets and liabilities of certain foreign subsidiaries are prepared in their respective local currencies and translated into U.S. dollars based on the current exchange rate in effect at the balance sheet dates, while income and expenses are translated at average rates for the periods presented. Translation adjustments have no effect on net income and are included in AOCI.

Statements of Cash Flows

For purposes of the consolidated statements of cash flows, Devon considers all highly liquid investments with original 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 14 for a discussion of amounts recorded for these liabilities.

Impact of Recently Issued Accounting Standards Not Yet Adopted

In December 2003, the FASB issued FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities*, ("FIN 46R") which addresses how a business enterprise should evaluate whether it has a controlling financial interest in an entity through means other than voting rights and accordingly should consolidate the entity. FIN 46R replaces FASB Interpretation No. 46, *Consolidation of Variable Interest Entities*, which was issued in January 2003. Devon will be required to apply FIN 46R to variable interests in variable interest entities ("VIEs") created after December 31, 2003. For variable interests in VIEs created before January 1, 2004, FIN 46R will be applied beginning on January 1, 2005. For any VIEs that must be consolidated under FIN 46R that were created before January 1, 2004, the assets, liabilities and noncontrolling interests of the VIE initially would be measured at their carrying amounts with any difference between the net amount added to the consolidated balance sheet and any previously recognized interest being recognized as the cumulative effect of a change in accounting principle. If determining the carrying amounts is not practicable, fair value at the date FIN 46R first applies may be used to measure the assets, liabilities and noncontrolling interest of the VIE. Devon owns no interests in variable interest entities; therefore, FIN 46R will not affect Devon's consolidated financial statements.

SFAS Statement No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*, ("SFAS No. 150") was issued in May 2003. SFAS No. 150 establishes standards for the classification and measurement of certain financial instruments with characteristics of both liabilities and equity. SFAS No. 150 also includes required disclosures for financial instruments within its scope. SFAS No. 150 was effective for instruments entered into or modified after May 31, 2003 and otherwise will be effective as of January 1, 2004, except for mandatorily redeemable financial instruments. For certain mandatorily redeemable financial instruments, SFAS No. 150 will be effective on January 1, 2005. The effective date has been deferred indefinitely for certain other types of mandatorily redeemable financial instruments. Devon currently does not have any financial instruments that are within the scope of SFAS No. 150.

2 BUSINESS COMBINATIONS AND PRO FORMA INFORMATION

Ocean Energy, Inc

On April 25, 2003, Devon completed its merger with Ocean Energy, Inc. ("Ocean"). In the transaction, Devon issued 0.414 shares of its common stock for each outstanding share of Ocean common stock (or a total of approximately 74 million shares). Also, Devon assumed approximately $1.8 billion of debt (current and long-term) from Ocean.

Devon acquired Ocean primarily for the significant production, development projects and exploration prospects in both the deepwater Gulf of Mexico and internationally and the additional producing assets onshore in the United States and in the shallower shelf regions of the Gulf of Mexico.

The calculation of the purchase price and the preliminary allocation to assets and liabilities as of April 25, 2003, are shown below. The purchase price allocation is preliminary because certain items such as the determination of the final tax bases and the fair value of certain assets and liabilities as of the acquisition date have not been completed.

		(IN MILLIONS, EXCEPT SHARE PRICE)
Calculation and allocation of purchase price:		
Shares of Devon common stock issued to Ocean stockholders		74
Average Devon stock price	$	48.05
Fair value of common stock issued	$	3,546
Plus estimated merger costs incurred		114
Plus fair value of Ocean convertible preferred stock assumed by a Devon subsidiary		64
Plus fair value of Ocean employee stock options assumed by Devon		124
Total purchase price		3,848
Plus fair value of liabilities assumed by Devon:		
Current liabilities		642
Long-term debt		1,436
Deferred revenue		97
Asset retirement obligation, long-term		121
Other noncurrent liabilities		86
Deferred income taxes		989
Total purchase price plus liabilities assumed	$	7,219
Fair value of assets acquired by Devon:		
Current assets	$	269
Proved oil and gas properties		4,262
Unproved oil and gas properties		1,060
Other property and equipment		84
Other noncurrent assets		38
Goodwill (none deductible for income taxes)		1,506
Total fair value of assets acquired	$	7,219

Mitchell Energy & Development Corp.

On January 24, 2002, Devon completed its merger with Mitchell Energy & Development Corp. ("Mitchell"). Under the terms of this merger, Devon issued approximately 30 million shares of Devon common stock and paid $1.6 billion in cash to the Mitchell stockholders. The cash portion of the acquisition was funded from borrowings under a $3.0 billion senior unsecured term loan credit facility (see Note 8).

Devon acquired Mitchell primarily for the significant development and exploitation projects in each of Mitchell's core areas, increased marketing and midstream operations and increased exposure to the North American natural gas market.

The calculation of the purchase price and the allocation to assets and liabilities as of January 24, 2002, are shown below.

		(IN MILLIONS, EXCEPT SHARE PRICE)
Calculation and allocation of purchase price:		
Shares of Devon common stock issued to Mitchell stockholders		30
Average Devon stock price	$	50.95
Fair value of common stock issued	$	1,512
Cash paid to Mitchell stockholders, calculated at $31 per outstanding common share of Mitchell		1,573
Fair value of Devon common stock and cash to be issued to Mitchell stockholders		3,085
Plus estimated merger costs incurred		84
Plus fair value of Mitchell employee stock options assumed by Devon		27
Total purchase price		3,196
Plus fair value of liabilities assumed by Devon:		
Current liabilities		190
Long-term debt		506
Other long-term liabilities		12
Deferred income taxes		798
Total purchase price plus liabilities assumed	$	4,818
Fair value of assets acquired by Devon:		
Current assets	$	169
Proved oil and gas properties		1,535
Unproved oil and gas properties		639
Marketing and midstream facilities and equipment		1,000
Other property and equipment		15
Other assets		103
Goodwill (none deductible for income taxes)		1,357
Total fair value of assets acquired	$	4,818

Pro Forma Information

Set forth in the following table is certain unaudited pro forma financial information for the years ended December 31, 2003, and 2002. The information has been prepared assuming the Ocean and Mitchell mergers were consummated on January 1, 2002. All pro forma information is based on estimates and assumptions deemed appropriate by Devon. The pro forma information is presented for illustrative purposes only. If the transactions had occurred in the past, Devon's operating results might have been different from those presented in the following table. The pro forma information should not be relied upon as an indication of the operating results that Devon would have achieved if the transactions had occurred on January 1, 2002. The pro forma information also should not be used as an indication of the future results that Devon will achieve after the transactions.

	PRO FORMA INFORMATION YEAR ENDED DECEMBER 31,	
	2003	2002
	(IN MILLIONS, EXCEPT PER SHARE AMOUNTS AND PRODUCTION VOLUMES) (UNAUDITED)	
Revenues		
Oil sales	$ 1,840	1,549
Gas sales	4,155	2,655
Natural gas liquids sales	416	304
Marketing and midstream revenues	1,461	1,069
Total revenues	7,872	5,577
Operating Costs and Expenses		
Lease operating expenses	948	835
Transportation costs	219	190
Production taxes	219	148
Marketing and midstream operating costs and expenses	1,174	873
Depreciation, depletion and amortization of property and equipment	1,984	1,862
Accretion of asset retirement obligation	38	—
General and administrative expenses	340	321
Reduction of carrying value of oil and gas properties	111	727
Total operating costs and expenses	5,033	4,956
Earnings from operations	2,839	621
Other Income (Expenses)		
Interest expense	(515)	(582)
Dividends on subsidiary's preferred stock	(3)	(3)
Effects of changes in foreign currency exchange rates	69	1
Change in fair value of financial instruments	1	28
Impairment of ChevronTexaco Corporation common stock	—	(205)
Other income	40	32
Net other expenses	(408)	(729)
Earnings (loss) from continuing operations before income taxes and cumulative effect of change in accounting principle	2,431	(108)
Income Tax Expense (Benefit)		
Current	219	47
Deferred	372	(199)
Total income tax expense (benefit)	591	(152)
Earnings from continuing operations before cumulative effect of change in accounting principle	1,840	44
Discontinued Operations		
Results of discontinued operations before income taxes (including net gain on disposal of $31 million in 2002)	—	54
Total income tax expense	—	9
Net results of discontinued operations	—	45
Earnings before cumulative effect of change in accounting principle	1,840	89
Cumulative effect of change in accounting principle	29	—
Net earnings	1,869	89
Preferred stock dividends	10	10
Net earnings applicable to common stockholders	$ 1,859	79

		PRO FORMA INFORMATION YEAR ENDED DECEMBER 31, 2003	2002
		(IN MILLIONS, EXCEPT PER SHARE AMOUNTS AND PRODUCTION VOLUMES) (UNAUDITED)	
Basic earnings per average common share outstanding:			
Earnings from continuing operations	$	7.90	0.15
Net results of discontinued operations		—	0.20
Cumulative effect of change in accounting principle		0.12	—
Net earnings	$	8.02	0.35
Diluted earnings per average common share outstanding:			
Earnings from continuing operations	$	7.69	0.14
Net results of discontinued operations		—	0.19
Cumulative effect of change in accounting principle		0.12	—
Net earnings	$	7.81	0.33
Weighted average common shares outstanding — basic		232	229
Weighted average common shares outstanding — diluted		240	236
Production volumes:			
Oil (MMBbls)		72	70
Gas (Bcf)		913	927
NGLs (MMBbls)		23	22
MMBoe		247	247

3 COMPREHENSIVE INCOME OR LOSS

Devon's comprehensive income or loss information is included in the accompanying consolidated statements of stockholders' equity and comprehensive income (loss). A summary of accumulated other comprehensive income or loss as of December 31, 2003, 2002 and 2001, and changes during each of the years then ended, is presented in the following table.

		FOREIGN CURRENCY TRANSLATION ADJUSTMENTS	CHANGE IN FAIR VALUE OF FINANCIAL INSTRUMENTS	MINIMUM PENSION LIABILITY ADJUSTMENTS	UNREALIZED GAIN (LOSS) ON MARKETABLE SECURITIES	TOTAL
				(IN MILLIONS)		
Balance as of December 31, 2000	$	(38)	—	—	(47)	(85)
2001 activity		(107)	243	(28)	36	144
Deferred taxes		—	(84)	11	(14)	(87)
2001 activity, net of deferred taxes		(107)	159	(17)	22	57
Balance as of December 31, 2001		(145)	159	(17)	(25)	(28)
2002 activity		46	(379)	(85)	41	(377)
Deferred taxes		—	123	31	(16)	138
2002 activity, net of deferred taxes		46	(256)	(54)	25	(239)
Balance as of December 31, 2002		(99)	(97)	(71)	—	(267)
2003 activity		894	(41)	28	141	1,022
Deferred taxes		(128)	3	(9)	(52)	(186)
2003 activity, net of deferred taxes		766	(38)	19	89	836
Balance as of December 31, 2003	$	667	(135)	(52)	89	569

The 2002 activity for unrealized gain (loss) on marketable securities includes additional unrealized losses of $164 million ($103 million net of taxes), offset by the recognition of a $205 million loss ($128 million net of taxes) in the statement of operations during 2002. The recognized loss was due to the impairment of the ChevronTexaco common stock owned by Devon.

4 SUPPLEMENTAL CASH FLOW INFORMATION

Cash payments (refunds) for interest and income taxes in 2003, 2002 and 2001 are presented below:

	YEAR ENDED DECEMBER 31, 2003	2002	2001
	(IN MILLIONS)		
Interest paid	$ 508	248	118
Income taxes paid (refunded)	$ 123	(12)	185

The 2003 Ocean merger, 2002 Mitchell merger and the 2001 acquisition of Anderson Exploration Ltd. involved non-cash consideration as presented below:

	OCEAN MERGER	MITCHELL MERGER	ANDERSON ACQUISITION
	(IN MILLIONS)		
Value of common stock issued	$ 3,546	1,512	—
Convertible preferred stock assumed	64	—	—
Employee stock options assumed	124	27	—
Liabilities assumed	2,382	824	1,301
Deferred tax liability created	989	798	1,394
Fair value of assets acquired with non-cash consideration	$ 7,105	3,161	2,695

5 ACCOUNTS RECEIVABLE

The components of accounts receivable included the following:

	DECEMBER 31, 2003	2002
	(IN MILLIONS)	
Oil, gas and natural gas liquids revenue accruals	$ 668	422
Joint interest billings	124	102
Marketing and midstream revenue accruals	106	73
Other	59	52
	957	649
Allowance for doubtful accounts	(11)	(10)
Net accounts receivable	$ 946	639

6 PROPERTY AND EQUIPMENT AND ASSET RETIREMENT OBLIGATIONS

Property and equipment included the following:

	DECEMBER 31, 2003	2002
	(IN MILLIONS)	
Oil and gas properties:		
Subject to amortization	$ 23,590	15,020
Not subject to amortization:		
Acquired in 2003	1,246	—
Acquired in 2002	636	730
Acquired in 2001	1,278	1,338
Acquired prior to 2001	176	221
Accumulated depreciation, depletion and amortization	(9,967)	(7,796)
Net oil and gas properties	16,959	9,513
Other property and equipment	1,620	1,477
Accumulated depreciation and amortization	(245)	(138)
Net other property and equipment	1,375	1,339
Property and equipment, net of accumulated depreciation, depletion and amortization	$ 18,334	10,852

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 at least annually. 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.

Depreciation, depletion and amortization of property and equipment consisted of the following components:

		YEAR ENDED DECEMBER 31,		
		2003	2002	2001
			(IN MILLIONS)	
Depreciation, depletion and amortization of oil and gas properties	$	1,668	1,106	793
Depreciation and amortization of other property and equipment		118	97	30
Amortization of other assets		7	8	8
Total	$	1,793	1,211	831

As described in Note 1, effective January 1, 2003, Devon adopted SFAS No. 143 and began recording asset retirement obligations for estimated property and equipment dismantlement, abandonment and restoration costs when the legal obligation is incurred. In accordance with SFAS No. 143, oil and gas properties subject to amortization and other property and equipment listed above include asset retirement costs associated with these asset retirement obligations. Following is a reconciliation of the asset retirement obligation from December 31, 2002, to December 31, 2003.

		(IN MILLIONS)
Asset retirement obligation as of December 31, 2002	$	—
Cumulative effect of change in accounting principle		453
Asset retirement obligation assumed from Ocean merger		134
Liabilities incurred		48
Liabilities settled		(37)
Liabilities assumed by others		(4)
Accretion expense on discounted obligation		36
Foreign currency translation adjustment		41
Asset retirement obligation as of December 31, 2003		671
Less current portion		42
Asset retirement obligation, long-term	$	629

7 INVESTMENT IN CHEVRONTEXACO CORPORATION COMMON STOCK

In the fourth quarter of 2002, Devon recorded a $205 million other-than-temporary impairment of its investment in shares of ChevronTexaco common stock. Devon acquired these shares in its August 1999 acquisition of PennzEnergy Company. The shares are deposited with an exchange agent for possible exchange for $760 million of debentures that are exchangeable into the ChevronTexaco shares. The debentures, which mature in August 2008, were also assumed by Devon in the 1999 PennzEnergy acquisition.

At the closing date of the PennzEnergy acquisition, Devon initially recorded the ChevronTexaco common shares at their fair value, which was $95.38 per share, or an aggregate value of $677 million. Since then, as the ChevronTexaco shares have fluctuated in market value, the value of the shares on Devon's balance sheet has been adjusted to the applicable market value. Through September 30, 2002, any decreases in the value of the ChevronTexaco common shares were determined by Devon to be temporary in nature. Therefore, the changes in value were recorded directly to stockholders' equity and were not recorded in Devon's results of operations through September 30, 2002.

The determination that a decline in value of the ChevronTexaco shares is temporary or other than temporary is subjective and influenced by many factors. Among these factors are the significance of the decline as a percentage of the original cost, the length of time the stock price has been below original cost, the performance of the stock price in relation to the stock price of its competitors within the industry and the market in general, and whether the decline is attributable to specific adverse conditions affecting ChevronTexaco.

Beginning in July 2002, the market value of ChevronTexaco common stock began a significant decline. The price per share decreased from $88.50 at June 30, 2002, to $69.25 per share at September 30, 2002, and to $66.48 per share at December 31, 2002. The year-end price of $66.48 represented a 25% decline since June 30, 2002, and a 30% decline from the original valuation in August 1999. As a result of the decline in value during the fourth quarter of 2002, Devon determined that the decline was other than temporary, as that term is defined by accounting rules. Therefore, the $205 million cumulative decrease in the value of the ChevronTexaco common shares from the initial acquisition in August 1999 to December 31, 2002, was recorded as a noncash charge to Devon's results of operations in the fourth quarter of 2002. Net of the applicable tax benefit, the charge reduced net earnings by $128 million.

During 2003, the share price of ChevronTexaco common stock has increased to $86.39 at December 31, 2003. As a result, the market value of Devon's investment in ChevronTexaco common stock increased $141 million from December 31, 2002, to December 31, 2003. The changes in the value of the shares since December 31, 2002, net of applicable taxes, have been recorded directly to stockholders' equity. However, depending on the future performance of ChevronTexaco's common stock, Devon may be required to record additional noncash charges in future periods if the value of such stock declines, and Devon determines that such declines are other than temporary.

8 LONG-TERM DEBT AND RELATED EXPENSES

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

		DECEMBER 31, 2003	DECEMBER 31, 2002
		(IN MILLIONS)	
Borrowings under credit facilities with banks	$	—	—
Commercial paper borrowings		—	—
$3 billion term loan credit facility due October 15, 2006		635	1,135
Debentures exchangeable into shares of ChevronTexaco Corporation common stock:			
4.90% due August 15, 2008		444	444
4.95% due August 15, 2008		316	316
Discount on exchangeable debentures		(83)	(98)
Zero coupon convertible senior debentures exchangeable into shares of Devon common stock, due June 27, 2020		404	388
Other debentures and notes:			
6.75% due February 15, 2004		211	211
8.05% due June 15, 2004		125	125
7.625% due July 1, 2005		125	—
7.25% due July 18, 2005		135	111
10.25% due November 1, 2005		236	236
2.75% due August 1, 2006		500	—
6.55% due August 2, 2006		155	127
4.375% due October 1, 2007		400	—
10.125% due November 15, 2009		177	177
6.75% due March 15, 2011		400	400
6.875% due September 30, 2011		1,750	1,750
7.25% due October 1, 2011		350	—
8.25% due July 1, 2018		125	—
7.50% due September 15, 2027		150	—
7.875% due September 30, 2031		1,250	1,250
7.95% due April 15, 2032		1,000	1,000
Other		4	—
Fair value adjustment on debt related to interest rate swaps		27	5
Net (discount) premium on other debentures and notes		82	(15)
		8,918	7,562
Less amount classified as current		338	—
Long-term debt	$	8,580	7,562

Maturities of long-term debt as of December 31, 2003, excluding the $1 million of net discounts and the $27 million fair value adjustment, are as follows (in millions):

2004	$	337
2005		497
2006		1,291
2007		400
2008		761
2009 and thereafter		5,606
Total	$	8,892

Credit Facilities with Banks

Devon has $1 billion of unsecured long-term credit facilities (the “Credit Facilities”). The Credit Facilities include a U.S. facility of $725 million (the “U.S. Facility”) and a Canadian facility of $275 million (the “Canadian Facility”). The $725 million U.S. Facility consists of a Tranche A facility of $200 million and a Tranche B facility of $525 million.

The Tranche A facility matures on October 15, 2004. Devon may borrow funds under the Tranche B facility until June 2, 2004 (the “Tranche B Revolving Period”). Devon may request that the Tranche B Revolving Period be extended an additional 364 days by notifying the agent bank of such request between 30 and 60 days prior to the end of the Tranche B Revolving Period. On June 2, 2004, at the end of the Tranche B Revolving Period, Devon may convert the then outstanding balance under the Tranche B facility to a one-year term loan by paying the Agent a fee of 25 basis points. The applicable borrowing rate would be at LIBOR plus 112.5 basis points. On December 31, 2003 and 2002, there were no borrowings outstanding under the $725 million U.S. Facility. The available capacity under the U.S. Facility as of December 31, 2003, net of outstanding letters of credit, was approximately $586 million.

Devon may borrow funds under the $275 million Canadian Facility until June 2, 2004 (the “Canadian Facility Revolving Period”). Devon may request that the Canadian Facility Revolving Period be extended an additional 364 days by notifying the agent bank of such request between 30 and 60 days prior to the end of the Canadian Facility Revolving Period. Debt outstanding as of the end of the Canadian Facility Revolving Period is payable in semiannual installments of 2.5% each for the following five years, with the final installment due five years and one day following the end of the Canadian Facility Revolving Period. On December 31, 2003 and 2002, there were no borrowings under the $275 million Canadian Facility. The available capacity under the Canadian Facility as of December 31, 2003, net of outstanding letters of credit, was approximately $214 million.

Under the terms of the Credit Facilities, Devon has the right to reallocate up to $100 million of the unused Tranche B facility maximum credit amount to the Canadian Facility. Conversely, Devon also has the right to reallocate up to $100 million of unused Canadian Facility maximum credit amount to the Tranche B Facility.

Amounts borrowed under the Credit Facilities bear interest at various fixed rate options that Devon may elect for periods up to six months. Such rates are generally less than the prime rate. Devon may also elect to borrow at the prime rate. The Credit Facilities provide for an annual facility fee of $1.4 million that is payable quarterly in arrears.

The agreements governing the Credit Facilities contain certain covenants and restrictions, including a maximum debt-to-capitalization ratio. At December 31, 2003, Devon was in compliance with such covenants and restrictions.

Commercial Paper

On August 29, 2000, Devon entered into a commercial paper program. Devon may borrow up to $725 million under the commercial paper program. Total borrowings under the U.S. Facility and the commercial paper program may not exceed $725 million. The commercial paper borrowings may have terms of up to 365 days and bear 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, London Interbank Offered Rate (LIBOR), or the money market rate as found on the commercial paper market. As of December 31, 2003 and 2002, Devon had no commercial paper debt outstanding.

$3 Billion Term Loan Credit Facility

On October 12, 2001, Devon and its wholly owned financing subsidiary, Devon Financing Corporation, U.L.C. (“Devon Financing”), entered into a new $3 billion senior unsecured term loan credit facility. The facility has a term of five years. Interest on borrowings under this facility may be based, at the borrower’s option, on LIBOR or on UBS Warburg LLC’s base rate (which is the higher of UBS Warburg’s prime commercial lending rate and the weighted average of rates on overnight Federal funds transactions with members of the Federal Reserve System plus 0.50%).

This $3 billion facility includes various rate options which can be elected by Devon, including a rate based on LIBOR plus a margin. The margin is based on Devon’s debt rating. Based on Devon’s current debt rating, the margin is 100 basis points. As of December 31, 2003, and 2002, the average interest rate on this facility was 2.2% and 2.5%, respectively.

This $3 billion facility was fully borrowed upon the closing of the Mitchell merger on January 24, 2002. As of December 31, 2003, and 2002, the remaining balance outstanding was $0.6 billion and $1.1 billion, respectively. The primary sources of the repayments were the issuance of $1.5 billion of debt securities, of which $1.3 billion was used to pay down the credit facility with the remainder used to pay down other debt, and $1.4 billion from the sale of certain oil and gas properties, of which $1.1 billion was used to pay down the credit facility. The terms of this facility require repayment of the remaining debt balance at maturity in October 2006. This credit facility contains certain covenants and restrictions, including a maximum allowed debt-to-capitalization ratio as defined in the credit facility. At December 31, 2003, Devon was in compliance with such covenants and restrictions.

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. The exchangeable debentures are exchangeable at the option of the holders at any time prior to maturity, unless previously redeemed, for shares of ChevronTexaco common stock. In lieu of delivering ChevronTexaco 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 ChevronTexaco 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, 2003, Devon beneficially owned approximately 7.1 million shares of ChevronTexaco 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 9.3283 shares of ChevronTexaco common stock, an exchange rate equivalent to $107.20 per share of ChevronTexaco stock.

The exchangeable debentures were assumed as part of the PennzEnergy merger. The fair values of the exchangeable debentures were determined as of August 17, 1999, based on market quotations. Under SFAS No. 133, the total fair value of the debentures has been allocated between the interest-bearing debt and the option to exchange ChevronTexaco 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%.

Zero Coupon Convertible Debentures

In June 2000, Devon privately sold zero coupon convertible senior debentures. The debentures were sold at a price of $464.13 per debenture with a yield to maturity of 3.875% per annum. Each of the 760,000 debentures is convertible into 5.7593 shares of Devon common stock. Devon may call the debentures at any time after five years, and a debenture holder has the right to require Devon to repurchase the debentures after five, 10 and 15 years, at the issue price plus accrued original issue discount and interest. The first put date is June 26, 2005, at an accreted value of $427 million. Devon has the right to satisfy its obligation by paying cash or issuing shares of Devon common stock with a value equal to its obligation. Devon's proceeds were approximately $346 million, net of debt issuance costs of approximately $7 million. Devon used the proceeds from the sale of these debentures to pay down other domestic long-term debt.

Other Debentures and Notes

Following are descriptions of the various other debentures and notes listed in the table presented at the beginning of this note.

6.75% Senior Notes due February 15, 2004 Devon assumed these senior notes in connection with the Mitchell merger. The fair value of these senior notes approximated the face value. As a result, no premium or discount was recorded on these senior notes.

8.05% Notes due June 15, 2004 In June 1999, Devon issued these notes for 98.758% of face value and Devon received total proceeds of $122 million after deducting related costs and expenses of $2 million. The notes are general unsecured obligations of Devon.

Ocean Debt In connection with the Ocean merger, Devon assumed $1.8 billion of debt. The table below summarizes the debt assumed, the fair value of the debt at April 25, 2003, and the effective interest rate. The premiums and discounts are being amortized or accreted using the effective interest method. All of the notes are general unsecured obligations of Devon.

DEBT ASSUMED	APRIL 25, 2003 FAIR VALUE OF DEBT ASSUMED	EFFECTIVE RATE OF DEBT ASSUMED
	(IN MILLIONS)	
Revolving credit line	$ 160	
Note payable	50	
Senior notes and senior subordinated notes:		
7.875% due August 2003 (principal of $100 million)	102	4.8%
7.625% due July 2005 (principal of $125 million)	139	3.0%
4.375% due October 2007 (principal of $400 million)	410	3.8%
8.375% due July 2008 (principal of $200 million)	208	7.4%
7.250% due September 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%
Other	6	
	1,797	
Less amount classified as current as of April 25, 2003	361	
Long-term debt	$ 1,436	

Change of control provisions required the outstanding borrowings under the credit facility and note payable to be fully paid immediately. Additionally, Devon was required to extend purchase offers for certain senior notes and the senior subordinated notes. As a result of these purchase offers, which expired on June 13, 2003, Devon paid $118 million for the aggregate principal amount tendered. The purchase price for each offer was 101 percent of the principal amount of the notes tendered plus accrued and unpaid interest to and including the purchase date. All notes that were not tendered remain outstanding except as described below.

Included in the $118 million of debt retired pursuant to the purchase offer were $13 million of the 8.375% notes and $57 million of the 7.875% notes. The remaining $195 million of 8.375% notes were called and redeemed on July 1, 2003. Additionally, the remaining $43 million of 7.875% senior notes were paid August 1, 2003, when they were due.

Anderson Debt In connection with the Anderson acquisition, Devon assumed $702 million of senior notes. The table below summarizes the debt assumed which remains outstanding, the fair value of the debt at October 15, 2001, and the effective interest rate of the debt assumed after determining the fair values of the respective notes using October 15, 2001, market interest rates. The premiums and discounts are being amortized or accreted 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)	
7.25% senior notes due 2005	$ 116	6.3%
6.55% senior notes due 2006	$ 129	6.5%
6.75% senior notes due 2011	$ 400	6.8%

2.75% Notes due August 1, 2006 On August 4, 2003, Devon issued these notes which are unsecured and unsubordinated obligations of Devon. The proceeds from the issuance of these debt securities, net of discounts and issuance costs, of $498 million, were used to repay amounts outstanding under the $3 billion term loan credit facility.

10.25% Debentures due November 1, 2005, and 10.125% Debentures due November 15, 2009 These debentures were assumed as part of the PennzEnergy acquisition. The fair values of the respective debentures were determined using August 17, 1999, market interest rates. As a result, premiums were recorded on these debentures which lowered their effective interest rates to 8.3% and 8.9% on the $236 million of 10.25% debentures and $177 million of 10.125% debentures, respectively. The premiums are 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, 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. The $3 billion of debt securities were structured in a manner that results in an expected weighted average after-tax borrowing rate of approximately 1.65%.

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 partially used to pay down $820 million on Devon's $3 billion term loan credit facility. The remaining $166 million of net proceeds was used in June 2002 to partially fund the early extinguishment of $175 million of 8.75% senior subordinated notes due June 15, 2007. The notes were redeemed at 104.375% of principal, or approximately $183 million.

Interest Expense

Following are the components of interest expense for the years 2003, 2002 and 2001:

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
		(IN MILLIONS)	
Interest based on debt outstanding	$ 531	499	200
Accretion of debt discount, net	3	13	10
Facility and agency fees	1	2	1
Amortization of capitalized loan costs	12	8	3
Capitalized interest	(50)	(4)	(3)
Early retirement premiums	—	8	7
Other	5	7	2
Total interest expense	$ 502	533	220

Effects of Changes in Foreign Currency Exchange Rates

The $400 million of 6.75% fixed-rate senior notes referred to in the first table of this note are payable by a Canadian subsidiary of Devon. However, the notes are denominated in U.S. dollars. Changes in the exchange rate between the U.S. dollar and the Canadian dollar from the dates the notes were assumed as part of an acquisition to the date of repayment increase or decrease the expected amount of Canadian dollars eventually required to repay the notes. Such changes in the Canadian dollar equivalent of the debt and certain cash and other working capital amounts of Devon's Canadian subsidiary which are also denominated in U.S. dollars are required to be included in determining net earnings for the period in which the exchange rate changed. As a result of changes in the rate of conversion of Canadian dollars to U.S. dollars, $69 million and $1 million was recorded as a reduction of expense in 2003 and 2002, respectively, and $11 million was recorded as an increase of expense in 2001.

9 INCOME TAXES

At December 31, 2003, Devon had the following carryforwards available to reduce future income taxes:

TYPES OF CARRYFORWARD	YEARS OF EXPIRATION	CARRYFORWARD AMOUNTS (IN MILLIONS)
Net operating loss – U.S. federal	2014 – 2023	$ 611
Net operating loss – various states	2004 – 2022	$ 346
Net operating loss – Canada	2005 – 2009	$ 473
Net operating loss – Azerbaijan	Indefinite	$ 67
Net operating loss – China	2004 – 2008	$ 19
Minimum tax credits	Indefinite	$ 56

All of the carryforward amounts shown above have been utilized for financial purposes to reduce the deferred tax liability.

The earnings (loss) before income taxes and the components of income tax expense (benefit) for the years 2003, 2002 and 2001 were as follows:

	YEAR ENDED DECEMBER 31, 2003	2002	2001
		(IN MILLIONS)	
Earnings (loss) from continuing operations before income taxes:			
U.S.	$ 1,603	354	458
Canada	603	(515)	(357)
International	39	27	(73)
Total	$ 2,245	(134)	28
Current income tax expense (benefit):			
U.S. federal	$ 125	(34)	23
Various states	6	11	6
Canada	(9)	28	8
International	71	18	11
Total current tax expense	193	23	48
Deferred income tax expense (benefit):			
U.S. federal	360	56	124
Various states	17	(14)	(32)
Canada	(16)	(253)	(145)
International	(40)	(5)	10
Total deferred tax expense (benefit)	321	(216)	(43)
Total income tax expense (benefit)	$ 514	(193)	5

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

Total income tax expense (benefit) differed from the amounts computed by applying the U.S. federal income tax rate to earnings (loss) from continuing operations before income taxes and cumulative effect of change in accounting principle as a result of the following:

	YEAR ENDED DECEMBER 31, 2003	2002	2001
		(IN MILLIONS)	
Expected income tax expense (benefit) based on U.S. statutory tax rate of 35%	$ 786	(47)	10
Financial expenses not deductible for income tax purposes	1	—	12
Dividends received deduction	(5)	(5)	(5)
Nonconventional fuel source credits	—	(19)	(19)
State income taxes	15	7	4
Taxation on foreign operations	(78)	(121)	5
Effect of Canadian tax rate reduction	(218)	—	—
Other	13	(8)	(2)
Total income tax expense (benefit)	$ 514	(193)	5

During 2003, the Canadian government enacted a statutory tax rate reduction that will be phased in through 2007. As presented in the table above, this rate reduction resulted in a $218 million benefit being recorded in 2003 related to the lower tax rates being applied to deferred tax liabilities outstanding as of December 31, 2002.

The tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities at December 31, 2003, and 2002 are presented below:

	DECEMBER 31, 2003	DECEMBER 31, 2002
	(IN MILLIONS)	
Deferred tax assets:		
Net operating loss carryforwards	$ 416	78
Minimum tax credit carryforwards	56	164
Fair value of financial instruments	44	46
Asset retirement obligations	281	—
Pension benefit obligation	85	42
Other	139	53
Total deferred tax assets	1,021	383
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	(5,052)	(2,863)
ChevronTexaco Corporation common stock	(190)	(147)
Long-term debt	(102)	—
Other	(47)	—
Total deferred tax liabilities	(5,391)	(3,010)
Net deferred tax liability	$ (4,370)	(2,627)

As shown in the above table, Devon has recognized $1.0 billion of deferred tax assets as of December 31, 2003. Such amount consists of $416 million of various carryforwards available to offset future income taxes. The carryforwards include federal net operating loss carryforwards, the majority of which do not begin to expire until 2014, state net operating loss carryforwards which expire primarily between 2004 and 2022, Canadian carryforwards which expire primarily between 2005 and 2009, Azerbaijani carryforwards which have no expiration, Chinese carryforwards which expire primarily between 2004 and 2008 and minimum tax credit 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 2004 and 2009. 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.

10 PREFERRED STOCK OF A SUBSIDIARY

At December 31, 2003, a subsidiary of Devon created in the Ocean merger had 38,000 shares of convertible preferred stock. In January 2004, these shares of convertible preferred stock were canceled and converted to 1,098,580 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 $52.39 for 20 consecutive trading days.

11 STOCKHOLDERS' EQUITY

The authorized capital stock of Devon consists of 800 million shares of common stock, par value $.10 per share (the "Common Stock"), 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.

There were 16 million exchangeable shares issued on December 10, 1998, in connection with the Northstar Energy Corporation combination. As of year-end 2003, 15 million of the exchangeable shares had been exchanged for shares of Devon's common stock. The exchangeable shares have rights identical to those of Devon's common stock and are exchangeable at any time into Devon's common stock on a one-for-one basis.

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. Effective January 22, 2002, the board voted to increase the designated shares from one million to two million. At December 31, 2003, 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 $10 or 100 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 100 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.

Stock Option Plans

Devon has outstanding stock options issued to key management and professional employees under three stock option plans adopted in 1993, 1997 and 2003 (the "1993 Plan," the "1997 Plan" and the "2003 Plan"). Options granted under the 1993 Plan and 1997 Plan remain exercisable by the employees owning such options, but no new options will be granted under these plans. At December 31, 2003, there were 225,000 and 6,382,000 options outstanding under the 1993 Plan and the 1997 Plan, respectively.

On April 25, 2003, Devon's stockholders adopted the 2003 Long-Term Incentive Plan. The new long-term incentive plan authorizes the compensation committee of Devon's board of directors to grant nonqualified and incentive stock options, stock appreciation rights, restricted stock awards, performance units and performance bonuses to selected employees. The plan also authorizes the grant of nonqualified stock options and restricted stock awards to directors. A total of 12,500,000 shares of Devon common stock have been reserved for issuance pursuant to the plan. Of these shares, no more than 2,500,000 shares may be granted as restricted stock, performance bonuses and performance units. During 2003, 653,000 restricted stock awards were granted which are subject to pro rata vesting over a four-year period. These awards had an aggregate fair value of $34 million and will be recorded as compensation expense over the vesting period.

The exercise price of stock options granted under the 2003 Plan may not be less than the estimated fair market value of the stock at the date of grant. Options granted are exercisable during a period established for each grant, which period may not exceed eight years from the date of grant. Under the 2003 Plan, the grantee must pay the exercise price in cash or in common stock, or a combination thereof, at the time that the option is exercised. The 2003 Plan is administered by a committee comprised of non-management members of the board of directors. The 2003 Plan expires on April 25, 2013. As of December 31, 2003, there were 1,487,000 options outstanding under the 2003 Plan. There were 10,360,000 options available for future grants as of December 31, 2003.

In addition to the stock options outstanding under the 1993 Plan, 1997 Plan and 2003 Plan there were approximately 4,674,000, 1,123,000, 281,000 and 1,173,000 stock options outstanding at the end of 2003 that were assumed as part of the Ocean merger, the Mitchell merger, the Santa Fe Snyder merger and the PennzEnergy merger, respectively.

A summary of the status of Devon's stock option plans as of December 31, 2001, 2002 and 2003, and changes during each of the years then ended, is presented below.

	OPTIONS OUTSTANDING		OPTIONS EXERCISABLE	
	NUMBER OUTSTANDING	WEIGHTED AVERAGE EXERCISE PRICE	NUMBER EXERCISABLE	WEIGHTED AVERAGE EXERCISE PRICE
	(IN THOUSANDS)		(IN THOUSANDS)	
Balance at December 31, 2000	7,356	$ 41.84	6,025	$ 40.72
Options granted	2,601	$ 35.43		
Options exercised	(1,505)	$ 31.13		
Options forfeited	(268)	$ 62.77		
Balance at December 31, 2001	8,184	$ 41.09	5,516	$ 41.93
Options granted	2,807	$ 45.77		
Options assumed in the Mitchell merger	1,554	$ 26.82		
Options exercised	(899)	$ 29.33		
Options forfeited	(415)	$ 47.12		
Balance at December 31, 2002	11,231	$ 41.00	6,991	$ 40.05
Options granted	1,504	$ 52.75		
Options assumed in the Ocean merger	7,926	$ 39.69		
Options exercised	(4,866)	$ 33.50		
Options forfeited	(450)	$ 52.11		
Balance at December 31, 2003	15,345	$ 43.53	11,460	$ 42.61

The weighted average fair values of options granted during 2003, 2002 and 2001 were $16.27, $15.25 and $13.17, respectively. The fair value of each option grant was estimated for disclosure purposes on the date of grant using the Black-Scholes Option Pricing Model with the following assumptions for 2003, 2002 and 2001, respectively: risk-free interest rates of 2.8%, 3.2% and 3.8%; dividend yields of 0.4%, 0.4% and 0.6%; expected lives of four, five and five years; and volatility of the price of the underlying common stock of 37.9%, 41.8% and 42.2%.

The following table summarizes information about Devon's stock options which were outstanding, and those which were exercisable, as of December 31, 2003:

	OPTIONS OUTSTANDING			OPTIONS EXERCISABLE	
RANGE OF EXERCISE PRICES	NUMBER OUTSTANDING	WEIGHTED AVERAGE REMAINING LIFE	WEIGHTED AVERAGE EXERCISE PRICE	NUMBER EXERCISABLE	WEIGHTED AVERAGE EXERCISE PRICE
	(IN THOUSANDS)			(IN THOUSANDS)	
$9.68 - $30.94	2,172	2.52 Years	$ 20.91	2,172	$ 20.91
$31.00 - $36.90	2,560	5.23 Years	$ 35.01	1,761	$ 35.09
$37.22 - $45.08	2,096	3.97 Years	$ 42.78	2,049	$ 42.87
$45.10 - $46.09	2,753	6.27 Years	$ 46.03	1,234	$ 45.96
$46.27 - $51.70	2,317	5.05 Years	$ 50.32	2,139	$ 50.30
$51.75 - $56.19	2,339	4.80 Years	$ 53.74	1,003	$ 54.94
$56.68 - $89.66	1,108	3.36 Years	$ 66.96	1,102	$ 67.01
	15,345	4.65 Years	$ 43.53	11,460	$ 42.61

Shareholder Rights Plan

Under Devon's shareholder rights plan, stockholders have one right for each share of Common Stock held. The rights become exercisable and separately transferable 10 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 $75.00, 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 April 16, 2005. The rights may be redeemed by Devon for $.01 per right until the rights become exercisable.

Dividends

Dividends on Devon's common stock were paid in 2003, 2002 and 2001 at a per share rate of $0.05 per quarter.

12 FINANCIAL INSTRUMENTS

The following table presents the carrying amounts and estimated fair values of Devon's financial instrument assets (liabilities) at December 31, 2003, and 2002.

		2003		2002	
		CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
		(IN MILLIONS)			
Investments	$	620	620	479	479
Oil and gas price hedge agreements	$	(186)	(186)	(144)	(144)
Interest rate swap agreements	$	18	18	(5)	(5)
Electricity hedge agreements	$	(1)	(1)	(2)	(2)
Foreign exchange hedge agreements	$	—	—	(1)	(1)
Embedded option in exchangeable debentures	$	(9)	(9)	(12)	(12)
Long-term debt	$	(8,918)	(9,680)	(7,562)	(8,425)
Preferred stock of a subsidiary	$	(55)	(63)	—	—

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, 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, 2003, and 2002.

Investments — The fair values of investments are based on quoted market prices.

Oil and Gas Price Hedge Agreements — The fair values of the oil and gas price hedges are 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 quotes obtained from the counterparty to the swap agreement.

Electricity Hedge Agreements — The fair values of the electricity hedges are based on an internal discounted cash flow calculation.

Foreign Exchange Hedge Agreements — The fair values of the foreign exchange agreements are based on either (a) an internal discounted cash flow calculation or (b) quotes obtained from brokers.

Embedded Option in Exchangeable Debentures — The fair values of the embedded options are based on quotes obtained from brokers.

Long-term Debt — The fair values of the fixed-rate long-term debt have been estimated 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 the floating-rate long-term debt are estimated to approximate the carrying amounts due to the fact that the interest rates paid on such debt are generally set for periods of three months or less.

Preferred Stock of a Subsidiary — The fair value of the preferred stock is based upon quotes obtained from brokers.

Devon's total hedged positions as of December 31, 2003, are set forth in the following tables.

Price Swaps

Through various price swaps, Devon has fixed the price it will receive on a portion of its oil and natural gas production in 2004 and 2005. These swaps will result in the fixed prices included below. Where necessary, the gas prices related to these swaps have been adjusted for certain transportation costs that are netted against the price recorded by Devon, and the price has also been adjusted for the Btu content of the gas production that has been hedged.

YEAR	OIL PRODUCTION BBLS/DAY	PRICE PER BBL
2004	64,000	$ 26.95
2005	22,000	$ 26.84

YEAR	GAS PRODUCTION MCF/DAY	PRICE PER MCF
2004	8,435	$ 3.10
2005	7,343	$ 2.97

Costless Price Collars

Devon has also entered into costless price collars that set a floor and ceiling price for a portion of its 2004 and 2005 oil production that otherwise is subject to floating prices. The floor and ceiling prices related to domestic and Canadian oil production are based on the NYMEX price. The floor and ceiling prices related to international oil production are based on the Brent price. If the NYMEX or Brent price is outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. Any such settlements will either increase or decrease Devon's oil revenues for the period. Because Devon's oil volumes are often sold at prices that differ from the NYMEX or Brent price due to differing quality (i.e., sweet crude versus sour crude) and transportation costs from different geographic areas, the floor and ceiling prices of the various collars do not reflect actual limits of Devon's realized prices for the production volumes related to the collars.

Devon has also entered into costless price collars that set a floor and ceiling price for a portion of its 2004 and 2005 natural gas production that otherwise is subject to floating prices. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. Any such settlements will either increase or decrease Devon's gas revenues for the period. Because Devon's gas volumes are often sold at prices that differ from the related regional indices, and due to differing Btu contents of gas produced, the floor and ceiling prices of the various collars do not reflect actual limits of Devon's realized prices for the production volumes related to the collars.

To simplify presentation, Devon's costless collars have been aggregated in the following table according to similar floor prices and similar ceiling prices. The floor and ceiling prices shown are weighted averages of the various collars in each aggregated group.

The international oil prices shown in the following tables have been adjusted to a NYMEX-based price, using Devon's estimates of future differentials between NYMEX and the Brent price upon which the collars are based.

The natural gas prices shown in the following tables have been adjusted to a NYMEX-based price, using Devon's estimates of future differentials between NYMEX and the specific regional indices upon which the collars are based. The floor and ceiling prices related to the domestic collars are based on various regional first-of-the-month price indices as published monthly by *Inside FERC*. The floor and ceiling prices related to the Canadian collars are based on the AECO index as published by the *Canadian Gas Price Reporter*.

	OIL PRODUCTION		
		WEIGHTED AVERAGE	
YEAR	BBLS/DAY	FLOOR PRICE PER BBL	CEILING PRICE PER BBL
2004	77,000	$ 21.90	$ 30.28
2005	50,000	$ 22.23	$ 28.23

	GAS PRODUCTION		
		WEIGHTED AVERAGE	
YEAR	MMBTU/DAY	FLOOR PRICE PER MMBTU	CEILING PRICE PER MMBTU
2004	1,194,945	$ 4.02	$ 7.43
2005	94,548	$ 3.83	$ 7.20

Interest Rate Swaps

Devon has also entered into a floating-to-fixed interest rate swap and fixed-to-floating interest rate swaps. Under the floating-to-fixed interest rate swap, Devon will record a fixed rate of 6.4% on a notional amount of $97 million in 2004 through 2006 and 6.3% on a notional amount of $30 million in 2007. Following is a table summarizing the fixed-to-floating interest rate swaps with the related debt instrument and notional amounts.

DEBT INSTRUMENT	NOTIONAL AMOUNT (IN MILLIONS)	FLOATING RATE
4.375% senior notes due in 2007	$ 400	LIBOR plus 40 basis points
10.25% bond due in 2005	$ 235	LIBOR plus 711 basis points
8.05% senior notes due in 2004	$ 125	LIBOR plus 336 basis points
2.75% notes due in 2006	$ 500	LIBOR less 26.8 basis points
7.625% senior notes due in 2005	$ 125	LIBOR plus 237 basis points

13 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.

During 2002, Devon established a funding policy regarding the Qualified Plans such that it would contribute the amount of funds necessary so that the Qualified Plans' assets would be approximately equal to the related accumulated benefit obligation by the end of 2004. As of December 31, 2003, the Qualified Plans' total accumulated benefit obligation was $397 million, which was $22 million more than the related assets. Devon's intentions are to fund this deficit during 2004. The actual amount of contributions required during this period 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 values of these trusts were $66 million and $53 million at December 31, 2003, and 2002, respectively, and are included in noncurrent 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 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 recorded in the consolidated balance sheet.

Benefit Obligations

Devon uses a measurement date of December 31 for its pension and postretirement benefit plans. The following table presents the plans' benefit obligations and the weighted-average actuarial assumptions used to calculate such obligations at December 31, 2003, and 2002. 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, 2003, and 2002 was $475 million and $424 million, respectively.

	PENSION BENEFITS		OTHER POSTRETIREMENT BENEFITS	
	2003	2002	2003	2002
	(IN MILLIONS)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 460	210	69	33
Service cost	12	9	1	1
Interest cost	31	28	4	4
Participant contributions	—	—	1	1
Amendments	1	—	(1)	—
Mergers and acquisitions	19	208	—	30
Foreign exchange rate changes	4	—	—	—
Settlement payments	—	(15)	—	—
Curtailment loss	—	2	—	—
Actuarial loss	28	42	3	6
Benefits paid	(43)	(24)	(7)	(7)
Benefit obligation at end of year	$ 512	460	70	68
Actuarial assumptions:				
Discount rate	6.23%	6.72%	6.25%	6.75%
Rate of compensation increase	4.88%	4.88%	5.00%	5.00%

For measurement purposes, a 10% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2004. The rate was assumed to decrease on a pro-rata basis annually to 5% in the year 2008 and remain at that level thereafter. A one-percentage-point increase in assumed health care cost trend rates would increase the December 31, 2003, postretirement benefit obligation by $2 million, while a one-percentage-point decrease in the same rate would decrease the postretirement benefit obligation by $3 million.

Plan Assets

The following table presents the plans' assets at December 31, 2003, and 2002.

	PENSION BENEFITS		OTHER POSTRETIREMENT BENEFITS	
	2003	2002	2003	2002
	(IN MILLIONS)			
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 281	156	—	—
Actual return on plan assets	70	(47)	—	—
Mergers and acquisitions	—	145	—	—
Employer contributions	67	66	6	6
Participant contributions	—	—	1	1
Settlement payments	—	(15)	—	—
Transfer to defined contribution plan	(3)	—	—	—
Benefits paid	(43)	(24)	(7)	(7)
Foreign exchange rate changes	3	—	—	—
Fair value of plan assets at end of year	$ 375	281	—	—

The plan assets for pension benefits in the table above excludes the assets held in trusts for the Supplemental Plans. However, employer contributions for pension benefits in the table above include $22 million in 2003 and $20 million in 2002 which were transferred from the trusts established for the Supplemental Plans.

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, 2003, the target investment allocation for Devon's 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. Derivatives or other speculative investments considered high-risk are generally prohibited.

The asset allocation for Devon's retirement plans at December 31, 2003, and 2002, and the target allocation for 2004, by asset category, follows:

	TARGET ALLOCATION	PERCENTAGE OF PLAN ASSETS AT YEAR END	
	2004	2003	2002
Equity securities	80%	79%	75%
Debt securities	20%	19%	23%
Other	—	2%	2%
Total	100%	100%	100%

Funded Status

The following table presents the funded status of the plans and the net amounts recognized in the consolidated balance sheets at December 31, 2003, and 2002.

	PENSION BENEFITS		OTHER POSTRETIREMENT BENEFITS	
	2003	2002	2003	2002
	(IN MILLIONS)			
Net amounts recognized in consolidated balance sheets:				
Fair value of plan assets	$ 375	281	—	—
Benefit obligations	512	460	70	68
Funded status	(137)	(179)	(70)	(68)
Unrecognized net actuarial loss	119	152	11	8
Unrecognized prior service cost (benefit)	5	5	(2)	(1)
Net amounts recognized	$ (13)	(22)	(61)	(61)
Components of net amounts recognized in the consolidated balance sheets:				
Accrued benefit cost	$ (102)	(140)	(61)	(61)
Intangible asset	4	5	—	—
Accumulated other comprehensive income	85	113	—	—
Net amount recognized	$ (13)	(22)	(61)	(61)

During 2003, the change in the minimum pension liability increased other comprehensive income by $28 million. During 2002, and 2001, the changes in the minimum pension liability decreased other comprehensive income by $85 million and $28 million, respectively.

Certain of Devon's pension and postretirement plans have a projected benefit obligation in excess of plan assets at December 31, 2003, and 2002. The aggregate benefit obligation and fair value of plan assets for these plans is included below.

	DECEMBER 31,	
	2003	2002
	(IN MILLIONS)	
Projected benefit obligation	$ 571	519
Fair value of plan assets	359	265

Certain of Devon's pension plans have an accumulated benefit obligation in excess of plan assets at December 31, 2003, and 2002. The aggregate accumulated benefit obligation and fair value of plan assets for these plans is included below.

	DECEMBER 31,	
	2003	2002
	(IN MILLIONS)	
Accumulated benefit obligation	$ 465	415
Fair value of plan assets	359	265

The plan assets included in the tables above exclude the Supplemental Plan trusts, which had a total value of $66 million and $53 million at December 31, 2003, and 2002, respectively.

Net Periodic Cost

The following table presents the plans' net periodic benefit cost and the weighted-average actuarial assumptions used to calculate such cost for the years ended December 31, 2003, 2002 and 2001.

		PENSION BENEFITS			OTHER POSTRETIREMENT BENEFITS		
		2003	2002	2001	2003	2002	2001
				(IN MILLIONS)			
Components of net periodic benefit cost:							
Service cost	$	12	9	5	1	1	1
Interest cost		31	28	13	4	4	4
Expected return on plan assets		(22)	(24)	(13)	—	—	—
Curtailment loss		1	—	—	—	—	—
Amortization of prior service cost		1	1	1	—	—	—
Recognized net actuarial loss		12	2	1	—	—	—
Net periodic benefit cost	$	35	16	7	5	5	5
Actuarial assumptions:							
Discount rate		6.53%	7.10%	7.65%	6.75%	7.15%	7.65%
Expected return on plan assets		8.25%	8.27%	8.50%	N/A	N/A	N/A
Rate of compensation increase		4.88%	4.88%	5.00%	5.00%	5.00%	5.00%

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. The expected long-term rate of return on plan assets is based on the target allocation of investment types in such assets.

Assumed health care cost trend rates have a significant effect on the amounts reported for the other postretirement benefit plans. A one-percentage-point change in the assumed health care cost trend rates would affect the total service and interest cost by less than $1 million.

In December 2003, the *Medicare Prescription Drug, Improvement and Modernization Act of 2003* was signed into law. Among other things, this new law expands Medicare to include a prescription drug benefit beginning in 2006. While this law is expected to decrease the obligation of the other postretirement benefit plans, this decrease is not reflected in either the benefit obligation or net periodic benefit cost amounts above. Recognition is being deferred until further guidance on accounting for the effects of the new law is issued.

Expected Cash Flows

Information about the expected cash flows for the pension and other postretirement benefit plans follows:

		PENSION BENEFITS	OTHER POSTRETIREMENT BENEFITS
		(IN MILLIONS)	
Employer contributions – 2004	$	52	8
Benefit payments:			
2004		28	8
2005		29	8
2006		30	8
2007		31	7
2008		33	7
2009 – 2013		192	30

Expected employer 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 2004, $7 million is expected to be funded from the trusts established for the Supplemental Plans and $8 million 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 incurred certain postemployment benefits to former or inactive employees who are not retirees. These benefits include salary continuance, severance and disability health care and life insurance. The accrued postemployment benefit liability was approximately $6 million at both December 31, 2003, and 2002.

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 $10 million, $8 million and $5 million for the years ended December 31, 2003, 2002 and 2001, 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 2003, 2002 and 2001, Devon's combined contributions to the Canadian defined contribution plan and the Canadian savings plan were $8 million, $8 million and $3 million, respectively.

14 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, 2003, Devon's consolidated balance sheet included $9 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. 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.

Devon is a defendant in certain private royalty owner litigation filed in Wyoming regarding deductibility of certain post production costs from royalties payable by Devon. The plaintiffs in these lawsuits propose to expand them into county or state-wide class actions relating specifically to transportation and related costs associated with Devon's Wyoming gas production. A significant portion of such production is, or will be, transported through facilities owned by Thunder Creek Gas Services, L.L.C., of which Devon owns a 75% interest. Devon believes that it has acted reasonably and paid royalties in good faith and in accordance with its obligations under its oil and gas leases and applicable law, and Devon does not believe that it is subject to material exposure in association with this litigation.

Tax Treatment of Exchangeable Debentures

As described more fully in Note 8, Devon has certain exchangeable debentures, with a principal amount totaling $760 million, which are exchangeable at the option of the holders into shares of ChevronTexaco common stock owned by Devon. The debentures were assumed, and the ChevronTexaco common stock was acquired, by Devon in the 1999 PennzEnergy merger.

The Internal Revenue Service is currently examining the 1998 income tax return of PennzEnergy's predecessor. In draft notices, the IRS has disagreed with certain tax treatments of the exchangeable debentures and similar exchangeable debentures retired in 1998. The IRS has not yet formally asserted a claim for additional taxes for 1998 related to the exchangeable debentures, but Devon believes it is probable that such an assertion will eventually be made.

Based upon the draft notices received from the IRS, Devon estimates that if the IRS formally asserts a claim for additional taxes for 1998 as a result of its current examination, the amount of such claim would approximate $68 million.

Devon does not agree with the positions that have been taken by the IRS in its draft documents, and will vigorously contest any claim of additional taxes. Although the outcome of this matter cannot be predicted with certainty, Devon, after consultation with legal counsel, believes that if the IRS formally asserts a claim for additional taxes regarding the treatment of the exchangeable debentures, Devon would likely prevail. Even if the IRS prevailed in this matter, Devon believes that any related increase in its 1998 taxable income would increase its tax basis in the ChevronTexaco common stock, or produce a similar tax benefit, and would therefore result in offsetting tax deductions in future taxable years upon the disposal of the ChevronTexaco common stock. Therefore, while the payment of any such additional taxes would reduce Devon's operating cash flow in the year of payment, it would not affect Devon's net earnings for any period, and the operating cash flow effect would reverse in future years.

If the IRS ultimately prevailed in this matter, any interest owed by Devon on such additional taxes would negatively impact Devon's operating cash flow and net earnings. However, Devon does not believe that such impact would be material to Devon's financial condition or results of operations.

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.

Operating Leases

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 $51 million, $37 million and $17 million in 2003, 2002 and 2001, 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 operating leases are for 20-year terms and contain various options whereby Devon may purchase the lessors' interests in the spars. Total rental expense included in lease operating expenses under these operating leases was $11 million in 2003. Devon has guaranteed that the spars will have residual values at the end of the operating leases equal to at least 10% of the fair value of the spars at the inception of the leases. The total guaranteed value is $20 million in 2022. However, such amount may be reduced under the terms of the lease agreements.

Devon also has two floating, production, storage and offloading (FPSO) facilities that are being leased under operating lease arrangements. One FPSO is being used in the Panyu project offshore China, and the other is being used in the Zafiro field offshore Equatorial Guinea. The China lease expires in September 2009 and the Equatorial Guinea lease expires in July 2011. Total rental expense included in lease operating expenses under these operating leases was $6 million in 2003.

The following is a schedule by year of future minimum rental payments required under office and equipment, spar and FPSO leases that have initial or remaining noncancelable lease terms in excess of one year as of December 31, 2003:

YEAR ENDING DECEMBER 31,	OFFICE AND EQUIPMENT LEASES	SPAR LEASES	FPSO LEASES
		(IN MILLIONS)	
2004	$ 47	11	20
2005	40	15	20
2006	36	15	20
2007	28	15	20
2008	24	15	20
Thereafter	85	243	36
Total minimum lease payments	$ 260	314	136

15 REDUCTION OF CARRYING VALUE OF OIL AND GAS PROPERTIES

Under the full cost method of accounting, the net book value of oil and gas properties, less related deferred income taxes and asset retirement obligations, may not exceed a calculated "ceiling." The ceiling limitation is the discounted estimated after-tax future net revenues from proved oil and gas properties plus the cost of properties not subject to amortization. The ceiling is determined separately by country. In calculating future net revenues, current prices and costs are generally held constant indefinitely. The net book value, less deferred tax liabilities and asset retirement obligations, is compared to the ceiling on a quarterly and annual basis. Any excess of the net book value, less related deferred taxes and asset retirement obligations, 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.

Under the purchase method of accounting for business combinations, acquired oil and gas properties are recorded at estimated fair value as of the date of purchase. Devon estimates such fair value using its estimates of future oil, gas and NGL prices. In contrast, the ceiling calculation dictates that prices in effect as of the last day of the applicable quarter are held constant indefinitely. Accordingly, the resulting value from the ceiling calculation is not necessarily indicative of the fair value of the reserves.

During 2003, 2002 and 2001, Devon reduced the carrying value of its oil and gas properties by $68 million, $651 million and $883 million, respectively, due to the full cost ceiling limitations. The after-tax effect of these reductions in 2003, 2002 and 2001 was $36 million, $371 million and $533 million, respectively. The following table summarizes these reductions by geographic area.

		YEAR ENDED DECEMBER 31,					
		2003		2002		2001	
		GROSS	NET OF TAXES	GROSS	NET OF TAXES	GROSS	NET OF TAXES
				(IN MILLIONS)			
United States	$	—	—	—	—	449	281
Canada		—	—	651	371	434	252
International		68	36	—	—	—	—
Total	$	68	36	651	371	883	533

The 2003 reduction in carrying value was related to properties in Egypt, Russia and Indonesia. The Egyptian reduction was primarily due to poor results of a development well that was unsuccessful in the primary objective. Partially as a result of this well, Devon revised Egyptian proved reserves downward. The Russian reduction was primarily the result of additional capital costs incurred as well as an increase in operating costs. The Indonesian reduction was primarily related to an increase in operating costs and a reduction in proved reserves. As a result, Devon's Egyptian, Russian and Indonesian costs to be recovered exceeded the related ceiling value by $26 million, $9 million and $1 million, respectively. These after-tax amounts resulted in pre-tax reductions of the carrying values of Devon's Egyptian, Russian and Indonesian oil and gas properties of $45 million, $19 million and $4 million, respectively, in the fourth quarter of 2003.

Additionally, during 2003, Devon elected to discontinue certain exploratory activities in Ghana, certain properties in Brazil and other smaller concessions. After meeting the drilling and capital commitments on these properties, Devon determined that these properties did not meet Devon's internal criteria to justify further investment. Accordingly, Devon recorded a $43 million charge associated with the impairment of these properties. The after-tax effect of this reduction was $38 million.

The 2002 Canadian reduction was primarily the result of lower prices. The recorded values of oil and gas properties added from the Anderson acquisition in 2001 were based on expected future oil and gas prices that were higher than the June 30, 2002, prices used to calculate the Canadian ceiling.

The 2001 domestic and Canadian reductions were also primarily the result of lower prices. The oil and gas properties added from the Anderson acquisition and other smaller acquisitions in 2001 were recorded at fair values that were based on expected future oil and gas prices higher than the December 31, 2001, prices used to calculate the ceiling.

Additionally, during 2001, Devon elected to abandon operations in Thailand, Malaysia, Qatar and on certain properties in Brazil. After meeting the drilling and capital commitments on these properties, Devon determined that these properties did not meet Devon's internal criteria to justify further investment. Accordingly, Devon recorded a $96 million charge associated with the impairment of these properties. The after-tax effect of this reduction was $78 million.

16 DISCONTINUED OPERATIONS

On April 18, 2002, Devon sold its Indonesian operations to PetroChina Company Limited for total cash consideration of $250 million. On October 25, 2002, Devon sold its Argentine operations to Petroleo Brasileiro S.A. for total cash consideration of $90 million. On January 27, 2003, Devon sold its Egyptian operations to IPR Transoil Corporation for total cash consideration of $7 million.

Under the provisions of SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, Devon reclassified its Indonesian, Argentine and Egyptian activities as discontinued operations. This reclassification affects the 2002 and 2001 presentation of financial results. Subsequent to the sale of its Egyptian and Indonesian operations, Devon acquired new Egyptian and Indonesian assets in the April 2003 Ocean merger. Amounts and activities related to these new Egyptian and Indonesian operations are included in Devon's continuing operations in 2003.

The major classes of assets and liabilities of these discontinued operations as of December 31, 2002, and revenues from these discontinued operations in 2002 and 2001 are presented below:

	DECEMBER 31, 2002
	(IN MILLIONS)
Major Classes of Assets and Liabilities	
Accounts receivable	$ 7
Total assets	$ 7

	YEAR ENDED DECEMBER 31, 2002	2001
	(IN MILLIONS)	
Revenues		
Oil sales	$ 72	174
Gas sales	7	12
NGL sales	1	1
Total revenues	$ 80	187

17 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 18.

Following is certain financial information regarding Devon's segments for 2003, 2002 and 2001. The revenues reported are all from external customers.

	U.S.	CANADA	INTERNATIONAL	TOTAL
		(IN MILLIONS)		
As of December 31, 2003				
Current assets	$ 1,411	643	310	2,364
Property and equipment, net of accumulated depreciation, depletion and amortization	10,753	4,900	2,681	18,334
Goodwill	3,073	2,336	68	5,477
Other assets	908	27	52	987
Total assets	$ 16,145	7,906	3,111	27,162
Current liabilities	$ 1,320	458	293	2,071
Other liabilities	371	20	10	401
Asset retirement obligation, long-term	386	218	25	629
Long-term debt	4,810	3,770	—	8,580
Preferred stock of a subsidiary	55	—	—	55
Deferred income taxes	2,471	1,433	466	4,370
Stockholders' equity	6,732	2,007	2,317	11,056
Total liabilities and stockholders' equity	$ 16,145	7,906	3,111	27,162

	U.S.	CANADA	INTERNATIONAL	TOTAL
		(IN MILLIONS)		
Year Ended December 31, 2003				
Revenues:				
Oil sales	$ 861	318	409	1,588
Gas sales	2,652	1,222	23	3,897
Natural gas liquids sales	289	114	4	407
Marketing and midstream revenues	1,443	17	—	1,460
Total revenues	5,245	1,671	436	7,352
Operating costs and expenses:				
Lease operating expenses	477	327	67	871
Transportation costs	140	65	2	207
Production taxes	194	3	7	204
Marketing and midstream operating costs and expenses	1,165	9	—	1,174
Depreciation, depletion and amortization of property and equipment	1,195	399	199	1,793
Accretion of asset retirement obligation	22	13	1	36
General and administrative expenses	252	43	12	307
Expenses related to mergers	7	—	—	7
Reduction in carrying value of oil and gas properties	—	—	111	111
Total operating costs and expenses	3,452	859	399	4,710
Earnings from operations	1,793	812	37	2,642
Other income (expenses):				
Interest expense	(211)	(285)	(6)	(502)
Dividends on subsidiary's preferred stock	(2)	—	—	(2)
Effects of changes in foreign currency exchange rates	—	69	—	69
Change in fair value of financial instruments	2	(1)	—	1
Other income	21	8	8	37
Net other income (expenses)	(190)	(209)	2	(397)
Earnings before income taxes and cumulative effect of change in accounting principle	1,603	603	39	2,245
Income tax expense (benefit):				
Current	131	(9)	71	193
Deferred	377	(16)	(40)	321
Total income tax expense (benefit)	508	(25)	31	514
Earnings before cumulative effect of change in accounting principle	1,095	628	8	1,731
Cumulative effect of change in accounting principle	11	5	—	16
Net earnings	$ 1,106	633	8	1,747
Capital expenditures	$ 1,579	704	304	2,587

	U.S.	CANADA	INTERNATIONAL	TOTAL
		(IN MILLIONS)		
As of December 31, 2002				
Current assets	$ 603	366	95	1,064
Property and equipment, net of accumulated depreciation, depletion and amortization	6,838	3,497	517	10,852
Goodwill	1,565	1,921	69	3,555
Other assets	723	31	—	754
Total assets	$ 9,729	5,815	681	16,225
Current liabilities	$ 626	344	72	1,042
Other liabilities	333	7	1	341
Long-term debt	3,545	4,017	—	7,562
Deferred income taxes	1,520	1,062	45	2,627
Stockholders' equity	3,705	385	563	4,653
Total liabilities and stockholders' equity	$ 9,729	5,815	681	16,225

		U.S.	CANADA	INTERNATIONAL	TOTAL
			(IN MILLIONS)		
Year Ended December 31, 2002					
Revenues:					
Oil sales	$	524	331	54	909
Gas sales		1,403	730	—	2,133
Natural gas liquids sales		192	83	—	275
Marketing and midstream revenues		985	14	—	999
Total revenues		3,104	1,158	54	4,316
Operating costs and expenses:					
Lease operating expenses		354	255	12	621
Transportation costs		99	55	—	154
Production taxes		104	7	—	111
Marketing and midstream operating costs and expenses		800	8	—	808
Depreciation, depletion and amortization of property and equipment		834	371	6	1,211
General and administrative expenses		166	40	13	219
Reduction in carrying value of oil and gas properties		—	651	—	651
Total operating costs and expenses		2,357	1,387	31	3,775
Earnings (loss) from operations		747	(229)	23	541
Other income (expenses):					
Interest expense		(235)	(295)	(3)	(533)
Effects of changes in foreign currency exchange rates		—	1	—	1
Change in fair value of financial instruments		31	(3)	—	28
Impairment of ChevronTexaco Corporation common stock		(205)	—	—	(205)
Other income		16	11	7	34
Net other income (expenses)		(393)	(286)	4	(675)
Earnings (loss) from continuing operations before income taxes		354	(515)	27	(134)
Income tax expense (benefit):					
Current		(23)	28	18	23
Deferred		42	(253)	(5)	(216)
Total income tax expense (benefit)		19	(225)	13	(193)
Earnings (loss) from continuing operations		335	(290)	14	59
Discontinued operations:					
Results of discontinued operations before income taxes		—	—	54	54
Income tax expense		—	—	9	9
Net results of discontinued operations		—	—	45	45
Net earnings (loss)	$	335	(290)	59	104
Capital expenditures	$	2,797	532	97	3,426

		U.S.	CANADA	INTERNATIONAL	TOTAL
			(IN MILLIONS)		
Year Ended December 31, 2001					
Revenues:					
Oil sales	$	586	146	52	784
Gas sales		1,571	307	—	1,878
Natural gas liquids sales		103	28	—	131
Marketing and midstream revenues		64	7	—	71
Total revenues		2,324	488	52	2,864
Operating costs and expenses:					
Lease operating expenses		340	110	17	467
Transportation costs		59	24	—	83
Production taxes		113	3	—	116
Marketing and midstream operating costs and expenses		43	4	—	47
Depreciation, depletion and amortization of property and equipment		647	166	18	831
Amortization of goodwill		34	—	—	34
General and administrative expenses		98	15	1	114
Expenses related to mergers		—	1	—	1
Reduction in carrying value of oil and gas properties		449	434	96	979
Total operating costs and expenses		1,783	757	132	2,672
Earnings (loss) from operations		541	(269)	(80)	192
Other income (expenses):					
Interest expense		(139)	(81)	—	(220)
Effects of changes in foreign currency exchange rates		—	(11)	—	(11)
Change in fair value of financial instruments		(1)	(1)	—	(2)
Other income		57	5	7	69
Net other income (expenses)		(83)	(88)	7	(164)
Earnings (loss) from continuing operations before income taxes and cumulative effect of change in accounting principle		458	(357)	(73)	28
Income tax expense (benefit):					
Current		29	8	11	48
Deferred		92	(145)	10	(43)
Total income tax expense (benefit)		121	(137)	21	5
Earnings (loss) from continuing operations before cumulative effect of change in accounting principle		337	(220)	(94)	23
Discontinued operations:					
Results of discontinued operations before income taxes		—	—	56	56
Income tax expense		—	—	25	25
Net results of discontinued operations		—	—	31	31
Earnings (loss) before cumulative effect of change in accounting principle		337	(220)	(63)	54
Cumulative effect of change in accounting principle		49	—	—	49
Net earnings (loss)	$	386	(220)	(63)	103
Capital expenditures	$	1,356	3,774	105	5,235

18 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*.

Costs Incurred

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

	TOTAL		
	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
	(IN MILLIONS)		
Property acquisition costs:			
Proved business combinations	$ 4,209	1,538	2,971
Deferred income taxes	—	—	84
Total proved	4,209	1,538	3,055
Unproved business combinations	1,063	639	1,433
Unproved other acquisitions	87	64	183
Deferred income taxes	—	—	27
Total unproved	1,150	703	1,643
Exploration costs	714	383	337
Development costs	1,853	1,140	916
Finding and development costs	7,926	3,764	5,951
Asset retirement costs – business combinations	134	—	—
Asset retirement costs – drilling	48	—	—
Less actual retirement expenditures	(37)	—	—
Costs incurred	$ 8,071	3,764	5,951

	DOMESTIC		
	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
	(IN MILLIONS)		
Property acquisition costs:			
Proved business combinations	$ 2,582	1,536	292
Deferred income taxes	—	—	79
Total proved	2,582	1,536	371
Unproved business combinations	551	639	—
Unproved other acquisitions	48	27	158
Deferred income taxes	—	—	27
Total unproved	599	666	185
Exploration costs	343	161	166
Development costs	1,191	808	726
Finding and development costs	4,715	3,171	1,448
Asset retirement costs – business combinations	115	—	—
Asset retirement costs – drilling	24	—	—
Less actual retirement expenditures	(22)	—	—
Costs incurred	$ 4,832	3,171	1,448

	CANADA		
	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
	(IN MILLIONS)		
Property acquisition costs:			
Proved business combinations	$ 26	2	2,621
Deferred income taxes	—	—	5
Total proved	26	2	2,626
Unproved business combinations	—	—	1,433
Unproved other acquisitions	39	28	24
Deferred income taxes	—	—	—
Total unproved	39	28	1,457
Exploration costs	214	207	126
Development costs	488	299	168
Finding and development costs	767	536	4,377
Asset retirement costs – business combinations	—	—	—
Asset retirement costs – drilling	17	—	—
Less actual retirement expenditures	(14)	—	—
Costs incurred	$ 770	536	4,377

		INTERNATIONAL		
		YEAR ENDED DECEMBER 31,		
		2003	2002	2001
		(IN MILLIONS)		
Property acquisition costs:				
Proved business combinations	$	1,601	—	58
Deferred income taxes		—	—	—
Total proved		1,601	—	58
Unproved business combinations		512	—	—
Unproved other acquisitions		—	9	1
Deferred income taxes		—	—	—
Total unproved		512	9	1
Exploration costs		157	15	45
Development costs		174	33	22
Finding and development costs		2,444	57	126
Asset retirement costs – business combinations		19	—	—
Asset retirement costs – drilling		7	—	—
Less actual retirement expenditures		(1)	—	—
Costs incurred	$	2,469	57	126

The preceding Total and International cost incurred tables exclude $16 million and $85 million in 2002 and 2001, respectively, related to discontinued operations.

As discussed in Note 1, effective January 1, 2003, Devon adopted SFAS No. 143. Prior to the adoption of SFAS No. 143, asset retirement costs were included in costs incurred when expenditures for such costs were made. Pursuant to the adoption of SFAS No. 143, such costs are now included in costs incurred when a legal obligation for incurring such costs has occurred.

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 $140 million, $97 million and $77 million in the years 2003, 2002 and 2001, respectively. Also, pursuant to the full cost method of accounting, 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 $50 million, $4 million and $3 million in the years 2003, 2002 and 2001, respectively.

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,		
		2003	2002	2001
		(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and natural gas liquids sales	$	5,892	3,317	2,793
Production and operating expenses		(1,282)	(886)	(666)
Depreciation, depletion and amortization		(1,668)	(1,106)	(793)
Accretion of asset retirement obligation		(36)	—	—
Amortization of goodwill		—	—	(34)
General and administrative expenses directly related to oil and gas producing activities		(48)	(29)	(17)
Reduction of carrying value of oil and gas properties		(111)	(651)	(979)
Income tax expense		(895)	(234)	(126)
Results of operations for oil and gas producing activities	$	1,852	411	178
Depreciation, depletion and amortization per equivalent barrel of production	$	7.33	5.88	6.30

		DOMESTIC		
		YEAR ENDED DECEMBER 31,		
		2003	2002	2001
		(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and natural gas liquids sales	$	3,802	2,119	2,260
Production and operating expenses		(811)	(557)	(512)
Depreciation, depletion and amortization		(1,084)	(737)	(615)
Accretion of asset retirement obligation		(22)	—	—
Amortization of goodwill		—	—	(34)
General and administrative expenses directly related to oil and gas producing activities		(27)	(14)	(9)
Reduction of carrying value of oil and gas properties		—	—	(449)
Income tax expense		(775)	(295)	(263)
Results of operations for oil and gas producing activities	$	1,083	516	378
Depreciation, depletion and amortization per equivalent barrel of production	$	7.42	6.22	6.48

		CANADA		
		YEAR ENDED DECEMBER 31,		
		2003	2002	2001
		(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and natural gas liquids sales	$	1,654	1,144	481
Production and operating expenses		(395)	(317)	(137)
Depreciation, depletion and amortization		(388)	(364)	(164)
Accretion of asset retirement obligation		(13)	—	—
General and administrative expenses directly related to oil and gas producing activities		(15)	(14)	(6)
Reduction of carrying value of oil and gas properties		—	(651)	(434)
Income tax (expense) benefit		(89)	74	102
Results of operations for oil and gas producing activities	$	754	(128)	(158)
Depreciation, depletion and amortization per equivalent barrel of production	$	6.17	5.39	5.74

		INTERNATIONAL		
		YEAR ENDED DECEMBER 31,		
		2003	2002	2001
		(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and natural gas liquids sales	$	436	54	52
Production and operating expenses		(76)	(12)	(17)
Depreciation, depletion and amortization		(196)	(5)	(14)
Accretion of asset retirement obligation		(1)	—	—
General and administrative expenses directly related to oil and gas producing activities		(6)	(1)	(2)
Reduction of carrying value of oil and gas properties		(111)	—	(96)
Income tax (expense) benefit		(31)	(13)	35
Results of operations for oil and gas producing activities	$	15	23	(42)
Depreciation, depletion and amortization per equivalent barrel of production	$	10.52	2.40	6.20

The preceding Total and International results of oil and gas producing activities tables exclude $19 million and $28 million in 2002 and 2001, respectively, related to discontinued operations.

Quantities of Oil and Gas Reserves

Set forth below is a summary of the reserves which were evaluated by independent petroleum consultants for each of the years ended 2003, 2002 and 2001.

	2003		2002		2001	
	PREPARED	AUDITED	PREPARED	AUDITED	PREPARED	AUDITED
Domestic	33%	37%	12%	61%	67%	9%
Canada	28%	—%	31%	—%	43%	—%
International	98%	—%	100%	—%	100%	—%

"Prepared" reserves are those estimates of 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.

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 2003 and 2002, and Paddock Lindstrom & Associates and Gilbert Laustsen Jung Associates, Ltd. in 2001. 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, 2003.

	TOTAL			
	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)	TOTAL (MMBOE)
Proved reserves as of December 31, 2000	406	3,045	50	963
Revisions of estimates	(14)	(284)	7	(54)
Extensions and discoveries	17	499	7	107
Purchase of reserves	166	2,267	52	596
Production	(36)	(489)	(8)	(126)
Sale of reserves	(12)	(14)	—	(14)
Proved reserves as of December 31, 2001	527	5,024	108	1,472
Revisions of estimates	(10)	(81)	—	(23)
Extensions and discoveries	36	570	11	142
Purchase of reserves	13	1,723	105	405
Production	(42)	(761)	(19)	(188)
Sale of reserves	(80)	(639)	(13)	(199)
Proved reserves as of December 31, 2002	444	5,836	192	1,609
Revisions of estimates	(9)	(9)	—	(11)
Extensions and discoveries	29	834	20	188
Purchase of reserves	262	1,650	19	556
Production	(62)	(863)	(22)	(228)
Sale of reserves	(3)	(132)	—	(25)
Proved reserves as of December 31, 2003	661	7,316	209	2,089
Proved developed reserves as of:				
December 31, 2000	232	2,595	46	711
December 31, 2001	298	3,911	88	1,038
December 31, 2002	260	4,618	150	1,180
December 31, 2003	408	5,980	179	1,584

	DOMESTIC			
	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)	TOTAL (MMBOE)
Proved reserves as of December 31, 2000	226	2,521	46	692
Revisions of estimates	(25)	(262)	7	(62)
Extensions and discoveries	12	360	5	77
Purchase of reserves	15	170	—	43
Production	(26)	(376)	(6)	(95)
Sale of reserves	(11)	(14)	—	(13)
Proved reserves as of December 31, 2001	191	2,399	52	642
Revisions of estimates	8	26	2	15
Extensions and discoveries	10	344	6	73
Purchase of reserves	12	1,722	105	404
Production	(24)	(482)	(14)	(118)
Sale of reserves	(50)	(457)	(5)	(131)
Proved reserves as of December 31, 2002	147	3,552	146	885
Revisions of estimates	(6)	57	(1)	2
Extensions and discoveries	12	510	14	111
Purchase of reserves	92	1,474	19	357
Production	(31)	(589)	(17)	(146)
Sale of reserves	(2)	(120)	—	(22)
Proved reserves as of December 31, 2003	212	4,884	161	1,187
Proved developed reserves as of:				
December 31, 2000	192	2,087	42	582
December 31, 2001	167	1,988	48	546
December 31, 2002	135	2,802	117	719
December 31, 2003	171	3,935	136	964

	CANADA			
	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)	TOTAL (MMBOE)
Proved reserves as of December 31, 2000	36	524	4	127
Revisions of estimates	—	(22)	—	(3)
Extensions and discoveries	5	139	2	30
Purchase of reserves	133	2,097	52	535
Production	(8)	(113)	(2)	(29)
Sale of reserves	—	—	—	—
Proved reserves as of December 31, 2001	166	2,625	56	660
Revisions of estimates	2	(107)	(2)	(18)
Extensions and discoveries	26	226	5	69
Purchase of reserves	1	1	—	1
Production	(16)	(279)	(5)	(68)
Sale of reserves	(30)	(182)	(8)	(68)
Proved reserves as of December 31, 2002	149	2,284	46	576
Revisions of estimates	(4)	(33)	1	(9)
Extensions and discoveries	16	324	6	76
Purchase of reserves	2	1	—	2
Production	(14)	(267)	(5)	(63)
Sale of reserves	(1)	(12)	—	(3)
Proved reserves as of December 31, 2003	148	2,297	48	579
Proved developed reserves as of:				
December 31, 2000	30	508	4	119
December 31, 2001	124	1,923	40	485
December 31, 2002	119	1,816	33	455
December 31, 2003	123	1,964	43	493

	INTERNATIONAL			
	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)	TOTAL (MMBOE)
Proved reserves as of December 31, 2000	144	—	—	144
Revisions of estimates	11	—	—	11
Extensions and discoveries	—	—	—	—
Purchase of reserves	18	—	—	18
Production	(2)	—	—	(2)
Sale of reserves	(1)	—	—	(1)
Proved reserves as of December 31, 2001	170	—	—	170
Revisions of estimates	(20)	—	—	(20)
Extensions and discoveries	—	—	—	—
Purchase of reserves	—	—	—	—
Production	(2)	—	—	(2)
Sale of reserves	—	—	—	—
Proved reserves as of December 31, 2002	148	—	—	148
Revisions of estimates	1	(33)	—	(4)
Extensions and discoveries	1	—	—	1
Purchase of reserves	168	175	—	197
Production	(17)	(7)	—	(19)
Sale of reserves	—	—	—	—
Proved reserves as of December 31, 2003	301	135	—	323
Proved developed reserves as of:				
December 31, 2000	10	—	—	10
December 31, 2001	7	—	—	7
December 31, 2002	6	—	—	6
December 31, 2003	114	81	—	127

The preceding International quantities of reserves are attributable to production sharing contracts with various foreign governments.

The preceding Total and International quantities of oil and gas reserves tables exclude the following proved reserves and proved developed reserves related to discontinued operations.

	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)	TOTAL (MMBOE)
Proved reserves as of:				
December 31, 2000	53	413	12	134
December 31, 2001	59	453	13	147
December 31, 2002	1	—	—	1
Proved developed reserves as of:				
December 31, 2000	29	35	—	35
December 31, 2001	26	37	—	32
December 31, 2002	—	—	—	—

Standardized Measure of Discounted Future Net Cash Flows

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

	TOTAL		
	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
	(IN MILLIONS)		
Future cash inflows	$ 60,562	38,399	21,769
Future costs:			
Development	(3,693)	(2,053)	(1,860)
Production	(16,232)	(9,076)	(7,682)
Future income tax expense	(12,078)	(8,737)	(3,050)
Future net cash flows	28,559	18,533	9,177
10% discount to reflect timing of cash flows	(12,638)	(8,168)	(4,162)
Standardized measure of discounted future net cash flows	$ 15,921	10,365	5,015

	DOMESTIC		
	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
	(IN MILLIONS)		
Future cash inflows	$ 36,602	20,571	9,861
Future costs:			
Development	(2,028)	(1,122)	(793)
Production	(10,788)	(5,871)	(3,774)
Future income tax expense	(6,848)	(3,911)	(759)
Future net cash flows	16,938	9,667	4,535
10% discount to reflect timing of cash flows	(7,435)	(4,157)	(1,734)
Standardized measure of discounted future net cash flows	$ 9,503	5,510	2,801

	CANADA		
	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
	(IN MILLIONS)		
Future cash inflows	$ 15,517	13,799	9,011
Future costs:			
Development	(1,051)	(633)	(922)
Production	(3,585)	(2,600)	(3,292)
Future income tax expense	(3,316)	(3,999)	(2,006)
Future net cash flows	7,565	6,567	2,791
10% discount to reflect timing of cash flows	(3,442)	(2,677)	(1,195)
Standardized measure of discounted future net cash flows	$ 4,123	3,890	1,596

	INTERNATIONAL		
	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
	(IN MILLIONS)		
Future cash inflows	$ 8,443	4,029	2,897
Future costs:			
Development	(614)	(298)	(145)
Production	(1,859)	(605)	(616)
Future income tax expense	(1,914)	(827)	(285)
Future net cash flows	4,056	2,299	1,851
10% discount to reflect timing of cash flows	(1,761)	(1,334)	(1,233)
Standardized measure of discounted future net cash flows	$ 2,295	965	618

Future cash inflows are computed by applying year-end prices (averaging $27.55 per barrel of oil, adjusted for transportation and other charges, $5.18 per Mcf of gas and $21.22 per barrel of natural gas liquids at December 31, 2003) 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 $3.7 billion of future development costs, $779 million, $596 million and $285 million are estimated to be spent in 2004, 2005 and 2006, respectively.

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.

Future development costs include not only development costs, but also future dismantlement, abandonment and rehabilitation costs. Included as part of the $3.7 billion of future development costs are $937 million of future dismantlement, abandonment and rehabilitation costs.

The preceding Total and International standardized measure of discounted future net cash flows tables exclude $21 million and $299 million in 2002 and 2001, respectively, related to discontinued 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,		
	2003	2002	2001
		(IN MILLIONS)	
Beginning balance	$ 10,365	5,015	12,065
Sales of oil, gas and natural gas liquids, net of production costs	(4,562)	(2,402)	(2,126)
Net changes in prices and production costs	2,645	9,122	(11,878)
Extensions, discoveries and improved recovery, net of future development costs	2,218	1,471	582
Purchase of reserves, net of future development costs	5,763	888	2,480
Development costs incurred during the period which reduced future development costs	1,022	175	314
Revisions of quantity estimates	(728)	(61)	(316)
Sales of reserves in place	(307)	(1,879)	(84)
Accretion of discount	1,531	692	1,708
Net change in income taxes	(2,305)	(2,673)	3,340
Other, primarily changes in timing	279	17	(1,070)
Ending balance	$ 15,921	10,365	5,015

The preceding table excludes $21 million, $299 million and $407 million as of December 31, 2002, 2001 and 2000, respectively, related to discontinued operations.

19 SUPPLEMENTAL QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Following is a summary of the unaudited interim results of operations for the years ended December 31, 2003, and 2002.

		2003			
	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER	FULL YEAR
		(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)			
Oil, gas and natural gas liquids sales	$ 1,237	1,478	1,613	1,564	5,892
Total revenues	$ 1,671	1,813	1,948	1,921	7,352
Net earnings before cumulative effect of change in accounting principle	$ 420	356	412	543	1,731
Net earnings	$ 436	356	412	543	1,747
Net earnings per common share:					
Basic:					
Net earnings before cumulative effect of change in accounting principle	$ 2.66	1.67	1.76	2.32	8.24
Cumulative effect of change in accounting principle	0.10	—	—	—	0.08
Total basic	$ 2.76	1.67	1.76	2.32	8.32
Diluted:					
Net earnings before cumulative effect of change in accounting principle	$ 2.57	1.62	1.71	2.25	8.00
Cumulative effect of change in accounting principle	0.10	—	—	—	0.07
Total diluted	$ 2.67	1.62	1.71	2.25	8.07

		2002			
	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER	FULL YEAR
		(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)			
Oil, gas and natural gas liquids sales	$ 743	882	766	926	3,317
Total revenues	$ 903	1,149	1,031	1,233	4,316
Net earnings (loss)	$ 62	(104)	62	84	104
Net earnings (loss) per common share:					
Basic	$ 0.41	(0.68)	0.38	0.52	0.61
Diluted	$ 0.40	(0.68)	0.37	0.52	0.61

The fourth quarter of 2003 includes a $218 million income tax benefit due to a statutory rate reduction of the Canadian tax rate. The per share effect of this tax benefit was $0.90. The fourth quarter of 2003 also includes $111 million of reduction of carrying value of oil and gas properties. The after-tax effect of the reduction in carrying value was $74 million or $0.31 per share.

The second quarter of 2002 includes $651 million of reduction of carrying value of oil and gas properties. The fourth quarter of 2002 includes $205 million for the impairment of ChevronTexaco Corporation common stock. The after-tax effect of these expenses was $371 million and $128 million, respectively. The per share effects of these quarterly reductions was $2.37 and $0.82, respectively.

Oil, gas and natural gas liquids sales for the first, second, third and fourth quarters of 2002 exclude $35 million, $21 million, $17 million and $7 million, respectively, related to discontinued operations.

Directors

JOHN W. NICHOLS, 89, 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.

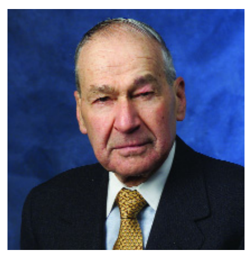
J. LARRY NICHOLS, 61, is a co-founder of Devon. He was named chairman of the board of directors in 2000. He has been a director since 1971. He served as president until 2003 and has served as chief executive officer since 1980. Nichols serves as a director of Smedvig ASA and Baker Hughes Inc. He also serves as a director of the Oklahoma City branch of the Federal Reserve Bank of Kansas City and several industry trade associations. Nichols has a Bachelor of Science degree in geology from Princeton University and a law degree from the University of Michigan.

MILTON CARROLL, 53, was appointed to the board of directors in 2003. Carroll previously served as a director of Ocean Energy, Inc. from 1997 to 2003. He was appointed chairman of the board of directors of CenterPoint Energy Inc. in 2002. Carroll has served as chairman of the board and chief executive officer of Instrument Products Inc. since 1977. He also serves as chairman of Health Care Service Corp. and is a director of Texas Eastern Products Pipeline Co. Partners, L.L.C. and EGL Inc.

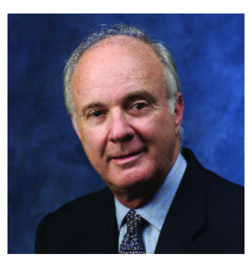
THOMAS F. FERGUSON, 67, has served as a director of Devon since 1982. He is chairman of the Audit Committee. Ferguson is the managing director of United Gulf Management Ltd., a wholly owned subsidiary of Kuwait Investment Projects Co. KSC. He has represented Kuwait Investment Projects Co. on the boards 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, 56, was appointed to the board of directors in 2003. Fluor served as a director of Ocean Energy, Inc. and its predecessors from 1980 to 2003. He 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.

DAVID M. GAVRIN, 69, is chairman of the Compensation Committee and has been a director since 1979. Gavrin has been a private investor since 1989 and is currently a director of MetBank Holding Corp. From 1978 to 1988, he was a general partner of Windcrest Partners, a private investment partnership in New York City. For fourteen years prior to that, he was an officer of Drexel Burnham Lambert Inc.



MICHAEL E. GELLERT, 72, is chairman of the Nominating and Governance Committee and has been a director since 1971. Gellert has been a general partner of Windcrest Partners, a private investment partnership in New York City, since 1967. From January 1958 until his retirement in October 1989, Gellert served in executive capacities with Drexel Burnham Lambert Inc. and its predecessors in New York City. In addition to serving as a member of Devon's board of directors, Gellert also serves on the boards of Humana Inc., Seacor Smit Inc., Six Flags Inc., Travelers Series Fund Inc., Dalet Technologies and Smith Barney World Funds.



JOHN A. HILL, 62, was elected to the board of directors in 2000. Hill 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 joining First Reserve Corp., Hill was president, chief executive officer and director of Marsh & McLennan Asset Management Co. 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 a director of TransMontaigne Inc., various companies controlled by First Reserve Corp. and Continuum Health Partners.

ROBERT L. HOWARD, 67, was appointed to the board of directors in 2003. Howard served as a director of Ocean Energy, Inc. from 1996 to 2003. Howard retired in 1995 from his position as vice president of Domestic Operations, Exploration and Production, of Shell Oil Co. He is also a director of Southwestern Energy Co. and McDermott International Inc.

WILLIAM J. JOHNSON, 69, was elected to the board of directors in 1999. Johnson has been a private consultant for the oil and gas industry for more than five years. 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 Petroleum Corp. since 1996. From 1991 to 1994, Johnson was president, chief operating officer and a director of Apache Corp.

MICHAEL M. KANOVSKY, 55, was a co-founder of Northstar Energy Corp., which was acquired by Devon in 1998. He served on Northstar's board of directors since 1982. He is president of Sky Energy Corp., a privately held energy corporation. Kanovsky continues to be active in the Canadian energy industry and is currently a director of ARC Resources Ltd. and Bonavista Petroleum Ltd.

CHARLES F. MITCHELL, 55, was appointed to the board of directors in 2003 upon completion of the merger with Ocean Energy. Mitchell served as a director of Ocean Energy, Inc. from 1995 to 2003. He is a physician and surgeon and has been a senior partner of ENT Medical Center in Baton Rouge, La., since 1985. Mitchell is involved in numerous private investments.

J. TODD MITCHELL, 45, was appointed to the board of directors in 2002. He served on the board of directors of Mitchell Energy & Development Corp. from 1993 to 2002. He has served as president of GPM Inc., a family-owned investment company, since 1998. Mitchell also has served as president of Dolomite Resources Inc., a privately owned mineral exploration and investments company, since 1987. Additionally, he has been chairman of Rock Solid Images, a privately owned seismic data analysis software company, since 1998.

ROBERT A. MOSBACHER JR., 52, was appointed to the board of directors in 1992. He has served as president and chief executive officer of Mosbacher Energy Co. since 1986. He was previously a director of PennzEnergy Co. and served on its Executive Committee. Mosbacher is currently a director of JPMorgan Chase & Co., Houston Regional Board and is on the executive committee of the U.S. Oil & Gas Association.

Senior Officers

JOHN RICHELS, 52, 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., where he held the position of executive vice president and chief financial officer from 1996 to 1998 and served on the board of directors from 1993 to 1996. Prior to joining Northstar, Richels was managing partner, chief operating partner and a member of the executive committee of the Canadian based national law firm, Bennett Jones. Richels previously served as a director of a number of publicly traded companies and is a former vice-chairman of the board of governors of the Canadian Association of Petroleum Producers. He holds a bachelor's degree in economics from York University and a law degree from the University of Windsor. While employed by Bennett Jones in the 1980s, Richels served as general counsel of the XV Olympic Winter Games Organizing Committee in Calgary.

BRIAN J. JENNINGS, 43, was appointed chief financial officer effective March 31, 2004, and elected to the position of senior vice president, Corporate Finance and Development, in 2002. Jennings joined Devon in March 2000 as vice president, Corporate Finance. Prior to joining Devon, Jennings was a managing director in the Energy Investment Banking Group of PaineWebber Inc. He began his banking career at Kidder, Peabody in 1989 before moving to Lehman Brothers in 1992 and later to PaineWebber in 1997. Jennings specialized in providing strategic advisory and corporate finance services to public and private companies in the exploration and production and oilfield service sectors. He began his energy career with ARCO International Oil & Gas, a subsidiary of Atlantic Richfield Co. Jennings received his Bachelor of Science in petroleum engineering from the University of Texas at Austin and his Master of Business Administration from the University of Chicago's Graduate School of Business.

DUKE R. LIGON, 62, was elected to the position of senior vice president and general counsel in 1999. Ligon joined Devon as vice president and general counsel in 1997. In addition to Ligon's primary role of managing Devon's corporate legal matters (including litigation), he has direct involvement with the company's governmental affairs and its merger and acquisition activities. Prior to joining Devon, Ligon practiced energy law for 12 years and last served as a partner at the law firm of Mayer, Brown & Platt (now Mayer, Brown, Rowe & Maw) in New York City. In addition, he was a senior vice president and managing director for investment banking at Bankers Trust Co. in New York City for 10 years. Ligon also served for three years in various positions with the U.S. Departments of the Interior and Treasury as well as the Department of Energy. Ligon holds an undergraduate degree in chemistry from Westminster College and a law degree from the University of Texas School of Law.

MARIAN J. MOON, 53, was elected to the position of senior vice president, Administration in 1999. Moon is responsible for Human Resources, Office Administration, Information Technology, Process Development and Corporate Governance. Moon has been with Devon for 19 years in various capacities, including manager of Corporate Finance and Corporate Secretary. Prior to joining Devon, Moon was employed for 11 years by Amarex Inc., an Oklahoma City-based oil and natural gas production and exploration firm. Her last position with Amarex was treasurer. Moon is a member of the American Society of Corporate Secretaries. She is a graduate of Valparaiso University.

DARRYL G. SMETTE, 56, 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, since 1989. He joined Devon in 1986 as manager of Gas Marketing. His marketing background includes 15 years with Energy Reserves Group Inc./BHP Petroleum (Americas) Inc. He last served as director of marketing with Energy Reserves Group/BHP. Smette 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.

Glossary of Terms

British thermal unit (Btu): A measure of heat value. An Mcf of natural gas is roughly equal to one million Btu.

Block: Refers to a contiguous leasehold position. In federal offshore waters, a block is typically 5,000 acres.

Coalbed natural gas: An unconventional gas resource that is present in certain coal deposits.

Deepwater: In offshore areas, water depths of greater than 600 feet.

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 its geographical location 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.

Heavy oil: Dense, viscous crude that often requires the application of heat to enable it to flow to the surface.

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.

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.

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.

Proppant: Granular particles mixed with the fracturing fluid to hold open the formation cracks created by a fracture treatment.

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 landowner's share of the value of minerals (oil and gas) produced on the property.

SEC Case: The method for calculating future net revenues from proved reserves as established by the Securities and Exchange Commission (SEC). Future oil and gas revenues are estimated using essentially fixed or unescalated prices. Future production and development costs also are unescalated and are subtracted from future revenues.

SEC @ 10% or SEC 10% present value: The future net revenue anticipated from proved reserves using the SEC Case, discounted at 10%.

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 is a developing technology that 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 producing heavy oil from oil sands by injecting steam underground. The heated heavy oil drains into a second horizontal producing well located directly below the steam injection well.

Stepout 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.

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.

Waterflood: A method of increasing oil recoveries from an existing reservoir. Water is injected through a special "water injection well" into an oil producing formation to force additional oil out of the reservoir rock and into nearby oil wells.

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
- MMBbl: One million barrels

BOD: Barrels of oil 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

MMcfd: Millions of cubic feet of gas 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

Common Stock Trading Data

QUARTER	HIGH	LOW	LAST	VOLUME
2002				
First	$ 49.10	$ 34.40	$ 48.77	70,651,200
Second	$ 52.28	$ 45.05	$ 49.28	62,348,000
Third	$ 49.70	$ 33.87	$ 48.25	67,042,000
Fourth	$ 53.10	$ 42.14	$ 45.90	71,894,800
2003				
First	$ 50.37	$ 42.45	$ 48.22	88,372,000
Second	$ 56.65	$ 45.25	$ 53.40	107,345,700
Third	$ 53.48	$ 46.38	$ 48.19	92,719,100
Fourth	$ 58.80	$ 45.90	$ 57.26	88,739,086

Investor Information

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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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Toll Free: (800) 829-8432

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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:
Judy Roberts
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Fax: (405) 552-7818
E-mail: judy.roberts@dvn.com

ANNUAL MEETING
Our annual shareholders' meeting will be held at 8 a.m. Central Time on Tuesday, June 8, 2004, in the Kingkade Room, Second Floor of The Renaissance Hotel, 10 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 American Stock Exchange (symbol: DVN). There are approximately 22,000 shareholders of record.

The Northstar exchangeable shares are traded on The Toronto Stock Exchange (symbol: NSX). They are exchangeable on a one-for-one basis for Devon common stock. The exchangeable shares also qualify as a domestic Canadian investment for Canadian institutional holders and have the same rights as Devon common stock.

DEVON'S WEBSITE
To learn more about Devon Energy, visit our website at: www.devonenergy.com. Devon's website contains press releases, SEC filings, answers to commonly asked questions, stock quote information and more.

Beneath the Surface

devon

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